Adams, Karen K NAE

From: Sandy Taylor [sandyt@saveoursound.org]
Sent: Thursday, February 24, 2005 6:08 PM
To: Energy, Wind NAE
Subject: Alliance to Protect Nantucket Sound's Revised Executive Summary

APNS Executive Summary.doc

4387

Karen Kirk-Adams
Cape Wind Energy EIS Project
U.S. Army Corps of Engineers, New England District
696 Virginia Road
Concord, MA 01742

On behalf of the Alliance to Protect Nantucket Sound, I am requesting
that
you substitute the enclosed Executive Summary in the DEIS comments
submitted
this morning.

Thank you.

Susan L. Nickerson
Executive Director

Sandy Taylor

Administrative Assistant
Alliance to Protect Nantucket Sound
397 Main Street
Hyannis, MA 02601
508-775-9767
508-775-9725 (fax)
sandyt@saveoursound.org

Adams, Karen K NAE

From: Brian Lannigan [blannigan@aol.com]
Sent: Thursday, February 24, 2005 5:50 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

How can we not view this option with an open mind. Our increased dependency on foreign oil and our continued degradation of our enviroment are only two of many reasons to allow this project to go forward. This "not in my back yard attitude" will continue to be played out in any location. Why is it that we must consistantly bow to the pressures of the rich at the expense of the masses? Please seriously consider this project if not for us but for our future generations.

004388

Sincerely,

Brian Lannigan

Sincerely,

Brian Lannigan
5 Tubwreck Drive
Dover, MA 02030

cc:
Capewind

Adams, Karen K NAE

From: Abigail Krich [info@capewind.org]
Sent: Thursday, February 24, 2005 5:55 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

004389

I am writing to express my full support of the proposed Cape Wind project in Nantucket Sound. I have lived in nearby Lexington, MA for 23 years and when I first heard of this project was excited that our State would be able to lead the way towards higher levels of clean, renewable energy.

From everything I know of the project, following it since its proposal and reading the draft environmental impact statement, it seems that the only reason not to go forth with the project is fear about bad aesthetics. For my part, I think new wind farms are beautiful. I actually go out of my way when I travel, be it in New York, Colorado, or Costa Rica to go visit wind farms because I love what they look like and the hope that they bring. I love the wilderness and appreciate unspoiled areas that are free of development to remind myself what the natural world looks like, but Nantucket sound is not an undeveloped, pristine area and to argue against the wind farm on these grounds is not appropriate.

I am looking forward to the cleaner energy the wind farm would produce, the local jobs it would create, the increased energy security it would give us, and the beautiful landmark it will become.

I urgue you to support the Cape Wind project to continue with their development plans.

Thank you

Sincerely,
Abigail Krich

Sincerely,

Abigail Krich
58 Baskin Rd
Lexington, MA 02421

cc:
Capewind

Adams, Karen K NAE

From: Donald Kelley [dkelley@brainshift.com]
Sent: Thursday, February 24, 2005 5:55 PM
To: Energy, Wind NAE
Subject: proposed wind turbines

004390

Dear Karen,

I want it to be known that I am in favor of the Cape Cod Wind Turbine Project. I am a "conservative" in the sense that I very much want to protect and conserve fundamental resources, including our natural resources.

As you know, personal interest does not always move individuals to "do the right thing." That is where we rely on elected officials to look after the public interest. I would like our officials to do the right thing on this issue, to get moving forward with alternative sources of energy and stop "exploring" the issue. Wind energy is a proven technology and increasingly cost-effective. The impact of wind turbines on the environment is minimal. As a long-time resident of Cape Cod (I grew up in Cotuit, not far from the proposed site), I would be proud if we hosted a project like this one.

Thank you for your dedication to this issue.

Best regards,

Donald Kelley

112 Fulton Spring Road
Medford, MA 02155
617-312-2130

Adams, Karen K NAE

From: Susan Williams [susanw@schoolofmortgagelending.com]
Sent: Thursday, February 24, 2005 6:02 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

PLEASE let me add my voice to this critical project. Not only will a part of New England benefit, but the entire utilities industry will see positive results. This project has ONLY but good outcomes for a great number of people.

I will celebrate your approval of the project.

004391

Sincerely,

Susan Williams
32 Stillman Rd
Saunderstown, RI 02874

cc:
Capewind

004392

Executive Summary – Alliance to Protect Nantucket Sound Comments on Draft EIS for Proposed Cape Wind Associates Energy Plant

CONCLUSIONS

The Cape Wind Associates (CWA) energy plant DEIS is seriously flawed; the review process is legally insufficient; and the proposed project is not in the public interest. The DEIS overstates the benefits of the proposed plant and understates the negative impacts and risks. In addition, the proposed project fails under many state and federal environmental laws. In light of these factors and others, the Corps must deny the Cape Wind application outright. If the Corps intends to continue its review, it must, at the very least, remedy the tremendous holes and glaring deficiencies in the existing review through a supplemental EIS.

The CWA project can <u>never</u> be approved at the federal, state, and local levels. Rather than continuing to pit the mutually compatible environmental goals of ocean conservation and renewable energy against each other, the Corps and CWA need to agree to a consensus-based process that removes Nantucket Sound and similar areas from risk while facilitating and expediting the review and approval of properly-sited renewable energy projects.

BACKGROUND

The Alliance to Protect Nantucket Sound (APNS) has assembled a team of experts to prepare comments on the DEIS. The APNS review of the DEIS is based upon the principles of protecting Nantucket Sound and its multiple public interest values by promoting a national system of ocean governance, establishing a comprehensive regional program for the development of wind energy and other forms of "clean energy," implementing an effective approach for combating air pollution and greenhouse gas emissions, and securing full cooperation between the Commonwealth and the federal government to protect and manage the ocean areas off the coast of Massachusetts.

THE REVIEW PROCESS IS FLAWED

The DEIS presents a biased discussion of the permit application and promotes the project, rather than analyzing it critically and objectively under federal and state laws, and suffers from serious technical deficiencies and errors.

In addition to the serious flaws in the DEIS, the procedure that the Corps has used to review the proposed wind energy plant is not adequate. The process conflicts with the goals of achieving comprehensive ocean governance and developing a renewable energy program. As supported by the recent decision of the First Circuit Court of Appeals in *Alliance to Protect Nantucket Sound v. U.S. Department of the Army*, there is no legal authority to allow private use of Nantucket Sound for wind energy development. CWA does not have permission from the federal government to use the Outer Continental Shelf (OCS) for its proposed project, and the Corps has no power to give it away. The Corps is required to address this issue as part of its permit application review, and its refusal to do so at this point in time is illegal and a disservice to the public. Nor is the Corps the appropriate agency to conduct the review of a project of this nature. The Corps itself has admitted it lacks expertise on these energy and offshore land issues. There are no standards to guide agency decision-making; there has been no programmatic review of offshore wind resources to identify preferred locations; and there has been no effort to comply with well-established principles of ocean governance.

THE PROPOSED PROJECT IS NOT IN THE PUBLIC INTEREST

The CWA application fails the public interest test under which section 10 permits must be judged. The purported benefits of the project are overstated, while the negative impacts are minimized, incorrectly analyzed, or ignored. Consequently, CWA's permit application must be denied.

The impacts of the proposed project are overwhelmingly negative. A review of each of the public interest factors indicates that the project weighs heavily against the public interest. Only one factor, energy, can be regarded as positive, and even this factor is speculative and of minimal benefit. The energy this project would produce is not needed now, and would be generated at a location where it is not of any benefit for the foreseeable future. The air quality benefits are unquantified and unexplained or insignificant. The same is true for greenhouse gas emission reductions. By contrast, there are numerous serious negative impacts. Fourteen of the public interest factors face negative effects, and many of these are very significant. These negative effects greatly outweigh the minor positive impacts.

As shown in the following matrix, the proposed project results in negative impacts under virtually every relevant factor included in the public interest test. The few factors for which the project has neutral or slightly positive consequences do not overcome the extreme negative effects. For this reason, the Corps must deny CWA's application.

FIGURE 1. SUMMARY OF PUBLIC INTEREST FACTORS

§ 320.4 Factor	Public Interest Effect			
	Positive	Not Applicable	Insignificant	Negative
General Environmental Concerns-Air Quality	✓*		✓*	
Energy Needs	✓**		✓**	
Conservation				✓
Economics				✓
Aesthetics				✓
Wetlands				✓
Historic Properties				✓
Fish and Wildlife Values				✓
Flood Hazards		✓		
Flood Plain Values		✓		
Land Use				✓
Navigation				✓
Shore Erosion and Accretion		✓		
Water Supply and Conservation		✓		
Water Quality				✓
Safety				✓
Food and Fiber Production			✓	✓
Mineral Needs				✓
Considerations of Property Ownership				✓
The Needs and Welfare of the People				✓

*Section 10 does not have a specific factor to address the purported air quality benefits upon which CWA stakes its claim of project benefits. For purposes of this review, air quality issues are considered under the "general environmental factor." Although we have assigned this factor a positive impact, this is done recognizing the speculative and insignificant nature of those benefits.

**As discussed in detail in these comments, the energy benefits of this project also are vastly overstated.

SUMMARY OF PUBLIC INTEREST FACTORS

General Environmental Concerns - Air Quality Impacts

CWA has attempted to justify its proposed project on purported improvements to air quality, reductions of harmful emissions, and combating global warming. However, the Corps and CWA have applied a conceptually flawed air pollution analysis that seriously overstates the benefits of the project. CWA and project supporters rely on air benefits as the principal justification for the proposed action. To the extent these benefits exist at all in certain limited areas, they are inconsequential.

The DEIS's most basic air quality claim is that construction of the proposed plant would lead to reductions in emissions of health-damaging pollutants from other New England power plants. The DEIS estimates the value of the resulting health benefits at $53 million per year. This is the largest single benefit claimed for the project, exceeding even the claims made for the value of cheaper electricity.

The DEIS makes this claim by first assuming that the proposed project will generate 1,489,200 megawatt hours of electricity a year. The DEIS claims, in effect, that the proposed project will "back out" an equal amount of electricity from fossil generation.

In fact, if the proposed project were constructed, it would not cause any reduction in these emissions, because of the nation's air pollution regulatory system that the DEIS does not mention. Moreover, even if such a back-out were to take place – and it will not – the amount of the back-out and any associated benefits would be dramatically smaller than the DEIS indicates.

The DEIS claim rests on a basic misunderstanding of how the air pollution control system already works to control power plant emissions in New England and around the country. These controls take the form of "cap and trade" programs. Such programs forbid the covered power plants, in the aggregate, to emit more than a defined "cap" amount of pollution. The government issues "allowances" to emit that amount and allocates them to individual power plants. No power plant can legally emit pollutants that it does not hold allowances to cover.

A cap and trade program makes clear that constructing the proposed project would not "back out" any emissions. Under a cap approach, whether that increased demand is met by the proposed project or by a fossil plant, emissions will remain the same.

Even taken on its own terms, the back-out analysis in the DEIS overestimates the amount of power the proposed project would generate and the amount of pollution that would be backed out.

The DEIS takes two different and inconsistent approaches to calculating the emission reduction benefits associated with the fossil-generated power it claims the proposed project will back out. At some points, the DEIS calculates this amount by referring to the emissions rates of the marginal contributor to the New England power pool, as calculated by ISO-NE for the year 2000.

However, in making the key computation of $53 million in annual health benefits stemming from backed-out pollution, the DEIS abandons this approach, and assumes instead that the proposed project would back out power from the Brayton Point and Salem Harbor plants, two of the dirtiest suppliers in the entire system.

There is no justification for this second approach. If any emissions are backed out, they will be emissions from the marginal producer. Correcting for this error by using the DEIS's own marginal emission rates would reduce the health benefits claimed by the DEIS by about two-thirds.

Moreover, even this figure is materially too high. Marginal emissions rates will decline steadily over time as air pollution requirements get tighter. Simply using 2002 data instead of the 2000 numbers in the DEIS reduces the calculated health benefits to $7 million.

General Environmental Concerns – Greenhouse Gas Emissions and Climate Change

The greenhouse benefits are not sufficiently large to justify the construction of the proposed project. The project's direct contribution to greenhouse gas reduction would be miniscule and temporary. The proposed project is one of the least cost-effective ways of reducing greenhouse gas emissions.

The DEIS claims that "once online the [Cape Wind] project could displace equivalent energy production from fossil plants that would otherwise annually emit on the order of 1,000,000 tons of carbon dioxide." Once again, the Corps has relied on outdated information provided by CWA in their original submittal, without acknowledging or incorporating more recent information that was readily available.

Over 7,400 MW of generating capacity have been added to the NEPOOL power supply over the past three years. This represents over 20% of the total generating capability within New England. Most of this capacity comes from highly efficient, natural gas-fired, combined cycle, generating facilities with state-of-the-art emission control equipment. The addition of this generation has had a significant impact on the marginal emissions rates in New England.

Based on the most recently available data, the numbers presented in the DEIS to support the CWA project are grossly overstated, as shown in the table below:

Comparison of Emission Reduction Calculations
DEIS Numbers vs Revised Values Based on Latest Available Data
(Tons/Year)

Emissions Reductions	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides
As Presented in DEIS	1,108,039	4,606	1,415
Based on Most Recent (2003) Data	877,883	1,489	521
Most Recent Data as a % of DEIS Data	79.2%	32.3%	36.8%

These values represent but a fraction of total annual world greenhouse gas emissions. Since global warming is equally caused by all emissions of greenhouse gasses world-wide, these figures describe the proposed plant's potential contribution to global warming control. The air pollution and global warming benefits the DEIS claims for the proposed project are exaggerated by at least one order of magnitude. The proposed project would not reduce air pollution materially. Such an insignificant contribution cannot be justified in light of the negative effects on a unique and environmentally sensitive area such as Nantucket Sound. Air quality and climate change issues are important to address, but the CWA project is the wrong way to do so, a fact the DEIS fails to present due to its flawed analytical approach.

Energy Needs

The proposed project is not necessary to meet future regional energy needs. While the DEIS claims there is a need for power in 2008, updated and geographically relevant analysis shows that there is no need for power in New England until the 2013-2015 timeframe. By that time, other technologies and forms of renewable energy would come online (including deepwater offshore wind) that would make the sacrifice of Nantucket Sound truly unnecessary. Cost-effective and efficient sources of renewable energy are clearly desirable, but the CWA project fails to meet this description. The DEIS fails to present a clear picture of how the CWA project fits into the overall energy picture.

There are several problems with the analysis put forth in the DEIS. First, the 1.9% growth rate of electricity demand quoted in the DEIS refers to the growth rate for electricity for the United States, not the growth rate of demand in New England, which is projected at only 1.3% over the ten-year analysis period of the CELT report.

Second, the DEIS refers to a report written by LaCapra Associates in 2002, in which it conducted an analysis of the need for power in the New England region based on the NEPOOL CELT report from the spring of 2002. Since that time, there have been two more CELT reports published by NEPOOL.

Third, LaCapra made adjustments to the Available Generating Capacity based on its own judgments of unit retirement schedules with no documentation of the assumptions used to make these judgments. By prematurely retiring these units in their analysis, it appears that LaCapra has created an artificial need for power in 2008.

Using the most recent NEPOOL CELT report issued in April 2004 and LaCapra's own criterion of 15% as the minimum reserve margin requirement before any additional generation is needed in New England, the next incremental MW of capacity is not needed until 2013. Assuming that funding of Demand Side Management (DSM) programs continues beyond 2010 (a highly probable event), the need for power would be extended beyond 2013.

The bottom line is that, according to NEPOOL's 2004 CELT report data and applying LaCapra 15% reserve margin, there is no need for power until well into the next decade. With added emphasis on DSM, this need could be postponed until well beyond the 2015 time frame. In consideration of these factors, the proposed project would have no impact whatsoever on the energy needs of the region.

Conservation

It is clear that a negative finding on the conservation factor is required due to Nantucket Sound's status as a sanctuary under Massachusetts law; its qualification as a federal marine protected area (MPA) under Executive Order 13158; and its qualifications for national marine sanctuary status. Under Massachusetts law, the very features of Nantucket Sound that would be *destroyed* by the CWA energy plant are specifically protected.

Economics

The DEIS grossly understates the economic impact of the project. The proposed project would have minimal impact, if any, on the region's consumption of fossil fuels and only minor reductions in air pollution. At the same time, it would result in the degradation of an ecological asset that plays a key role in the area's economy, substantial costs imposed on many different groups, and significant economic risks. The costs and risks of the project outweigh the potential benefits by a vast margin.

The DEIS does not account for all of the direct costs of the proposed project, e.g., the loss of revenue for the use and occupation of public lands and waters. The costs for major repairs and decommissioning also are underestimated in the DEIS.

Output overestimated:

The proposed project will likely produce less electricity than estimated and any electricity it produces probably would not displace electricity derived from fossil fuels, but rather electricity derived from other renewable sources of energy: biomass, landfill gas, or wind resources elsewhere. Consequently, the cost-savings for consumers and the human-health benefits would be far less than estimated.

The DEIS is expected to weigh the project impacts against its anticipated benefits. The two largest stated project benefits—a claimed $25 million in reduced power costs and $53 million in public health benefits—are directly proportional to the assumed facility power output – i.e., 1,489,200 MWh. To quantify benefits, the DEIS relied exclusively upon the project proponent's own power output estimates and studies while making no attempt independently to validate their claims.

CWA project performance is not justified using existing wind performance data. The output used to compute benefits (1,489,200 MWh) is equivalent to an annual capacity factor of 36.3% (if 468 MW) to 40.5% (if 420 MW). This performance claim far exceeds current operating experience at existing wind farms. Recent operating experience of existing New England land-based wind projects is Searsburg, Vermont, at 20.4% in 2003; Hull, Massachusetts, at 26.9% for project lifetime; Princeton, Massachusetts at 21.6% for 2002; and the more recent Madison, New York, wind project at 19.2% in 2003. The DEIS provides no evidence to support the claim for a 35-50% better performance than the Hull, Massachusetts, project located along the Massachusetts coastline that may have somewhat similar prevailing offshore wind and icing conditions.

While there are no U.S. offshore wind facilities, such facilities exist in Europe. The Danish offshore wind turbine performance in 2003 averaged only 29.4% in 2003 and 31.9% for the first 11 months in 2004. The Danish project most similar to the proposed project, the 160 MW Horns Rev wind plant in the North Sea, averaged only a 24.1% capacity factor in the first 11 months of 2004.

The existing operating data from both U.S. onshore and European offshore projects are unable to support the use of an average project capacity factor above 30 percent. The EIS contains no onsite wind tower data to confirm the developer's much higher power output estimate, despite the fact that CWA constructed a so-called data tower for that very purpose.

Overall, the combination of the historical wind turbine operating data and the projections using existing local wind datasets suggests that a lower project capacity factor of 25-30% (1,025,000-1,230,000 MWh) should have been used to calculate wind project impacts, not 36% (1,489,200 MWh).

Tourism, fishing, and property values:

The proposed project is likely to have significant, negative impacts on the value of recreational activities and on the area's tourism industry, with tourists perhaps reducing annual spending by $57 - $123 million.

It is also likely to affect the fishing industry negatively. One hundred thirty turbines, located in an area where currents are strong, would pose a significant hazard and cause the industry to avoid the area altogether, causing participants in commercial fishing a significant loss in income or giving rise to additional costs and risks of fishing among the turbines.

A broader review of all the relevant evidence indicates that the project is expected to lower property values, both directly, by degrading the scenic amenities of properties with views of Nantucket Sound, and indirectly, by depressing the area's recreation/tourism industry.

The DEIS also does not consider economic risks associated with the proposed project, such as financial risks, ecological risks, and navigation risks.

Overstated cost savings:

The DEIS suggests that one of the largest benefits of the proposed project would be a $25 million annual savings for New England customers based upon a March 2002 LaCapra study. The analysis is built upon an overly optimistic power output (1,486,000 MWh) and the assumption that the wind project output would have significant effect on marginal costs during peak demand prices. A review of the wind data and operating experience suggests that the proposed project output would be far less than assumed in the analysis. In addition, the project output during the high-cost peaking summer demand periods was often minimal to none at all. The combination of these factors suggests that the March 2002 LaCapra study significantly overstated the "annual savings."

Second, the simplified DEIS analysis does not reflect the net costs since it excludes the large subsidies being paid by the taxpayers and ratepayers that offset these purported "annual savings." The LaCapra calculations exclude the taxpayer subsidized federal tax credits, ratepayer-subsidized renewable energy credits, state-subsidized corporate tax exemption, and local tax exemptions. According to the Beacon Hill Institute (BHI), public subsidies will be made available in the form of a federal production tax credit with a present value estimated at $98 million, state green credits estimated at a value of $125 million and accelerated depreciation that has a present value effect of approximately $58 million, for a total of $281 million.

Aesthetics

The DEIS fails to conduct an analysis of the aesthetic impacts of the proposed project. The Corps has failed to follow its own guidance in this regard. It limits the scope of aesthetic impacts to historic properties. In addition, the DEIS fails to evaluate the impact to the culture and economy of Cape Cod and the Islands of changing the dominant views from a natural seascape to an enormous industrial facility. It is widely recognized that tourists and recreationists are attracted to the aesthetics of Cape Cod's seascape and cultural heritage associated with the traditional maritime lifestyle. The DEIS recognizes that the aesthetic impacts to all the properties that it considers are "adverse," even to properties that are as far away as 15 miles. It is therefore reasonable to anticipate that these adverse effects will be detrimental to the tourism and recreation-related economy of the Cape and Islands.

Wetlands

Wetlands impacts are equated with section 404 jurisdiction, which now applies to the project site as a result of the clarified and expanded state boundaries. The CWA wind-energy plant will have negative effects on wetlands through work associated with cable installation. If proper precautions are taken, this impact will not be significant, but it will be negative. More significant are the impacts associated with the use of erosion mats (or rip-rap if the mats are not effective) around the monopiles. These mats are designed to trap sand and will result in alteration of the sea floor configuration, as well as impacts to benthic species covered by the mats. These mats constitute fill under section 404, and no permit application has been filed for this purpose.

Historic Properties

The DEIS demonstrates that the proposed project will violate federal historic preservation laws and weigh heavily against the public interest by causing immitigable adverse impacts to certain historic properties and failing to consider potential impacts to others.

The proposed project will directly and adversely affect two historic properties of exceptional national significance to the United States that have been designated by the Secretary of the Interior as National Historic Landmarks: the Nantucket Historic District and the Kennedy Compound. Under section 110f of the National Historic Preservation Act (NHPA), the Corps must minimize harm to both of these properties to the "maximum extent possible." In this case, the only way to meet this obligation is to mandate that the CWA project be constructed outside of Nantucket Sound.

Second, the Corps' failure to consider visual effects to numerous historic properties violates section 106 of NHPA. That provision requires federal agencies to consider visual effects to any property "included in *or eligible for* inclusion in the National Register." At the request of APNS, a qualified historian has identified at least 23 historic properties not assessed by the Corps, including two properties included on the National Register, one property that has been determined eligible for inclusion, and at least 20 properties that are eligible for inclusion on the National Register.

Fish and Wildlife Values

Even a cursory review of the impacts of the proposed project on fish and wildlife resources leads to the conclusion that the project will significantly adversely impact wildlife. The proposed development will substantially alter important habitat for many species and result in ongoing disturbance to the ecosystem. Although the DEIS has not adequately evaluated a number of these impacts, and therefore cannot reach any rational conclusion regarding the scope of the potential impacts, it is nonetheless apparent that the project will have serious negative impacts on fish and wildlife values. Consequently, the public interest in fish and wildlife values is not served by approval of this project.

Land Use

The CWA wind energy plant will have negative public interest impacts on land use. There is a profound negative land use impact derived from the fact that the project would be located on the federally-controlled, public trust lands and waters of Nantucket Sound. CWA does not have, and cannot obtain, any property right or authorization for this purpose. It will "use" this federal "land," in violation of the public trust, with no compensation to the U.S. Treasury or right to do so. CWA would exclude other parties from making use of this public land and water resource, again with no right or authority to do so. It would be in trespass on federal property, and create land/water use conflicts with many other parties who seek to use the Sound for recreation, fishing, navigation, transportation, aesthetic enjoyment, sand dredging for beach replenishment, and other activities. There also will be numerous adverse effects under the land use factor as determined by the Cape Cod Commission Act. These deficiencies and the flaws in the DEIS have caused the Cape Cod Commission staff to call for a supplemental EIS.

Navigation

The proposed plant is incompatible with the marine transportation needs of the area and creates unacceptable risks to the environment and shipping. The DEIS analysis fails to address these impacts adequately. The placement of the proposed Horseshoe Shoal, Tuckernuck Shoal and Handkerchief Shoal sites are at odds with common international practice and threaten disruption of Nantucket Sound's Main Channel. The negative impacts of this project to marine transportation and public safety are significant and broad, and they pose unnecessary and unacceptable risks to cruise liner, ferry, oil transport, fishing and recreational vessels and their users.

The CWA project fails to make allowances for keeping wind plant boundaries at a suitable distance from established navigation channels and ferry routes, indicating a lack of understanding of the area in which hazards to safe navigation are posed by the wind plant. A review of existing offshore wind facilities reveals that, in contrast to the Nantucket Sound proposals, offshore wind facilities worldwide have been purposely located miles away from any active shipping channels. The Horseshoe Shoal proposal is placed directly adjacent (800 feet) to the Nantucket Sound Main Channel. In this location, no protection is afforded, as is repeatedly claimed in the DEIS, to prevent large ship and tanker collisions with the many turbines to be built along the Main Channel.

The DEIS conveys a false sense of safety and security about the risks that the turbines pose to ships, boats, passengers and the environment. It dismisses the real risks presented by vessels blown off-course, whose machinery or steering fails or whose operators make mistakes. The DEIS also claims that "physical water depth restrictions" limit the potential for a vessel to collide with a turbine. In fact, nearly 80% of the turbines are in deep enough water to be struck by the deepest vessels that routinely use the Main Channel. Such large vessels traveling at 10 knots would have less than one minute to react before traversing 800 feet and striking the nearest wind tower.

The DEIS wrongly concludes that the Cape Wind energy project will have no adverse effect on civil and military radar and communications. The United Kingdom's (UK's) Maritime and Coastguard Agency (MCA) completed a recent analysis and concluded that the presence of a wind facility produced strong maritime radar distortion not only on vessels operating within the wind energy plant but also on vessels operating up to 1½ nautical miles from the wind facility. The study also noted interference with ship collision avoidance systems, with VHF radio communications, and potentially with aircraft communications on distress frequencies. The MCA has recommended a follow-on study to further examine this interference and to recommend minimum distances that wind energy plants should be located from navigation channels and shipping routes. The Corps has not addressed these public interest concerns.

The UK Ministry of Defence also assessed the impact of wind facilities proposed to be located within the line of sight of air defense, air traffic control, and weather radar. As a result, the UK has established a list of safeguarded sites, consisting of 40 airports and military sites, where the authorities must formally review any proposed WTG installation. These are serious potential concerns for the Cape Wind project, and they have not been addressed by the Corps.

The DEIS fails to address the safety and navigation concerns that have been repeatedly expressed by the most frequent users of the waterways of Nantucket Sound. The DEIS contains no record of letters from The Woods Hole, Martha's Vineyard and Nantucket Steamship Authority and Hy-Line Cruises, expressing safety objections and concerns over the project. It also fails to address in any meaningful way the serious concerns of the Masters and crews of the ferry boat lines carrying thousands of passengers on the long-established routes directly adjacent to the proposed wind project.

The DEIS provides no discussion or analysis to establish a baseline of pollution incidents and consequences within the vicinity of the proposed wind facility. The DEIS provides no significant information or data concerning the impact that construction, operation and decommissioning of the facility will have on the frequency, size or consequence of marine pollution incidents for the proposed sites or to Nantucket Sound. In contrast, a recently conducted independent study which examined the result of a probable tankship/turbine collision revealed extensive contamination adversely impacting and killing especially sensitive biological resources in the Nantucket Sound ecosystem resulting from such an occurrence. This study clearly indicates the need for additional spill impact analysis by the project proponent to facilitate a more realistic environmental impact review by the public and local, state and federal governments. It also demonstrates clearly the negative public interest effects of the CWA project under this factor.

Water Quality

The impacts of the project to water quality have not been adequately addressed. The discharge of a pollutant to waters of the United States requires a National Pollutant Discharge Elimination System permit. The location of the project also means that the discharge must comply with EPA's Ocean Discharge Guidelines. The Guidelines require that EPA determine whether a proposed discharge will result in "unreasonable degradation of the marine environment." The DEIS does not adequately discuss the issue of wastewater discharges or the Ocean Discharge Guidelines. As noted above, this failure, combined with the oil spill risk created by the project, compels a negative public interest finding.

Safety

The DEIS for the proposed project inadequately addresses a number of issues that either directly or indirectly affect the public's safety and well-being in the region. These include: extreme weather impacts on the proposed facility; worker safety and facility access; and exposure to oil and hazardous substances. The proposed project may present safety hazards to employees/contractors of the proposed offshore facility. Transit to and from the facility may become difficult, and docking in heavy seas and winds may present significant safety hazards. Effects of hurricane/extreme storm events on public safety for onshore and offshore alternatives are not addressed in the DEIS.

Discussions with current and retired Steamship Authority and Hy-Line Cruise personnel and other local pilots revealed that seasonal sea ice does interfere with navigation in Nantucket Sound, requiring aggressive ice breaking activities during significant ice events. Further, given substantial ice occurrence in Nantucket Sound, the DEIS should address issues such as the likely rafting of ice around the offshore structures, the immediate proximity of the proposed plant to the Main Channel, and the risks posed by ice thrown from rotor blades.

The nine surrounding coastal towns have expressed concern over the devastating environmental effects of an oil spill within the confined shoreline of Nantucket Sound. In their letters, the Boards of Selectmen demanded that the potential effects of an oil spill be properly charted and disclosed for proper evaluation by local, state and federal agencies prior to the release of the DEIS. An independent analysis was conducted on potential spill impacts from either: 1) a tanker collision with a turbine, or 2) the transformer and diesel oils stored on the transformer platform. The result indicates that a significant oil spill event in Nantucket Sound would directly impact the Sound, Cape Cod, Martha's Vineyard, Nantucket, Vineyard Sound, proximal portions of the Atlantic Ocean and the Elizabethan Islands. Significant direct and indirect adverse impacts to the rich biological, cultural and recreational resources of the area would occur in the event of such a spill, potentially resulting in additional substantial impacts to public safety (through contaminated seafood ingestion and dermal exposure to spilled oil) and the regional economy (through adverse impacts to the fishing industry, aquaculture and tourism). A tanker collision with a wind turbine, whether rupturing two or all of the tanker's cargo tanks, would severely impact the Nantucket Sound ecosystem, killing especially sensitive fish and shellfish resources and wildlife. The larger spill is predicted to coat 217 miles of coastline, and cover

425 square miles of the Sound's surface and 869 square miles of the subsurface of the Sound.

The DEIS fails to consider in its public interest review the hazard of allowing vessels to approach the wind towers. A safety radius should have been investigated to protect: 1) the boating public and ferries from a blade breaking from its hub and being thrown; 2) vessels with masthead heights exceeding 75 feet; and 3) small boats losing control in eddy currents generated by the tower foundations. The failure to address these issues, as well as the problems noted above, compels a negative public interest finding under this factor.

Food and Fiber Production

It is likely that the proposed project will have a negative impact on food and fiber production. The construction and operation of the proposed plant will cause a localized disturbance to marine life. There will almost certainly be a reduction in productivity over the 24-square mile area and beyond. Turbidity plumes and sedimentation resulting from construction activities, scour, and anchor sweep have been greatly underestimated. The likely impact of this disturbance is that juvenile and adult fish would move away from the plumes and leave the area. Others would suffer lethal or sub-lethal effects. Seemingly localized impacts would cause population changes accumulating up the food chain with less and less predictable results higher up the trophic scale.

The fisheries community that has evolved at Horseshoe Shoal is dependent upon an open, sandy shoal environment. Conversion to a habitat dominated by high relief structures with their associated sounds, vibrations, and locally changed water flow patterns would disrupt the current finfish communities. Lacking anti-fouling protection, the turbines would quickly become encrusted with barnacles, seaweed, mollusks, etc. These 130 mini-ecosystems would likely attract some species and be avoided by others. The net effect is to cause a negative impact on fishing productivity.

Mineral Needs

The CWA wind energy plant will conflict with mineral needs. The Town of Barnstable has filed for the rights to dredge for sand on Horsehoe Shoal. This sand is needed for replenishment of eroding beaches. This proposed activity would be conducted under existing regulations, which clearly create a right for Barnstable to do so. The CWA project, which would interfere with this lawful dredging activity, can obtain no rights to use Horsehoe Shoal. In addition, the massive wind energy project would impede these dredging rights by removing areas from access, creating navigation problems, and interposing on any rights awarded to the Town.

Considerations of Property Ownership

The resources of Nantucket Sound are the public trust property of the general public, and they cannot be taken over by this private development company. The affected OCS area is under the control of the United States and cannot be alienated without an act of Congress. Moreover, CWA seeks to avoid paying anything for the use of this property, by providing competitive bidding, rents or royalties. There could be no more dramatic examples of a *negative* property ownership.

The project will also negatively affect private property rights. This project will result in a large decline in property values for all landowners included within the viewshed of the CWA energy project. This fact is documented in the economic analysis prepared by the Beacon Hill Institute, where it is projected that property values will decline an estimated $1.35 billion.

The Needs and Welfare of the People

The fact that the previous factors are *overwhelmingly negative* means that "the needs and welfare of the people" will be harmed by the CWA wind energy plant.

This conclusion is bolstered by the strong negative impact this project will have on other factors such as national security. As discussed above, the effects of this project on national security are significantly adverse, particularly given the interference that this project will have on domestic security detection systems.

The DEIS wrongly concludes that the Cape Wind energy project will have no adverse effect on civil and military radar and communications. Several British offshore wind energy projects have been canceled, denied or delayed because of interference with defense surveillance radar and air traffic control systems. The UK Ministry of Defence (MOD) has blocked five offshore wind farms because they could interfere with military aviation radar and the flight paths of nearby bases. The Corps has not addressed this potentially serious issue as it relates to the Cape Wind project. This concern was further raised in November 2004, when three regional airports, concerned about the 400,000 flights a year within the region, filed a formal appeal of the FAA's determination of "no adverse effect." This FAA appeal is still under investigation.

The DEIS overlooks the military PAVE PAWS early warning radar system, located on Otis Air Force Base, which is the backbone of the east coast terrestrial air defense system from Canada to Florida. PAVE PAWS is located approximately 20 miles from the primary and alternative wind energy plant sites. The negative effect of wind facilities already noted in the UK may compromise the integrity of the east coast air defense system.

In addition, public recreation will be seriously harmed by the project. The affected area is popular for use by recreational boaters, and will be removed from such use. Moreover, the scenic value of the entire affected recreational resource will be seriously degraded by the project. The U.S. Coast Guard's ability to protect the surrounding coastal areas from illegal activity and security threats, and its search and rescue (SAR) missions for small boats, fishing vessels and survivors, will be impeded by the wind facility's presence. There will be clear identifiable conditions and circumstances, such as fog or high winds, when the mere presence of the WTGs will preclude a quick SAR response and rescue by a Coast Guard helicopter. This will likely delay both the search as well as the rescue response within the 24-square mile area of the wind facility until a Coast Guard boat can arrive on-scene only to be faced with radar, VHF tracking and possible communication interference attributable to the WTGs.

As shown by this discussion, the public interest factors weigh heavily against this project. When they are considered together, it is clear that the permit application fails the public interest test by an overwhelming margin.

OBJECTIONS BY STATE REQUIRE PERMIT DENIAL

The necessity of denying the permit application is even more compelling when the Commonwealth's objections are taken into account. Governor Romney has expressed the Commonwealth's clear opposition to this project. The views of affected states must be accorded special deference under both Corps regulations and the President's recent Executive Order on Facilitation of Cooperative Conservation.

As has been evident from the start of the review process, the official position of the state is one of total opposition to the project. Governor Romney, Attorney General Reilly, Senator Kennedy, and Congressman Delahunt, the Representative for the region, have each, on numerous occasions, expressed their opposition to the proposed project. For example, Governor Romney testified at a Corps hearing on December 7, 2004, in which he stated, "I've seen wind farms, and they are not pretty. If we want them in Massachusetts, we'll build them, but not here on Nantucket Sound." At that same meeting, Attorney General Reilly commented, "I support renewable energy, but there is a right and a wrong way and this is the wrong way. . . . This is no wind farm; it's a power plant." Each of these state officials has expressed opposition in formal letters as well. As such, the Corps must take those comments into account as "a reflection of local factors of the public interest." The Corps must defer to the position of the State and affected local governments and deny the application. The Corps' section 10 regulations require that the permit be denied due to state opposition.

THE PROJECT FAILS UNDER MANY FEDERAL AND STATE ENVIRONMENTAL LAWS

The application fails under a host of environmental laws, including the Coastal Zone Management Act, Endangered Species Act, Marine Mammal Protection Act, Migratory Bird Treaty Act, National Historic Preservation Act, the federal public trust doctrine, and State laws, including the Massachusetts Ocean Sanctuaries Act, the Energy Facilities Siting Board statute, the Massachusetts Waterways statute, the Cape Cod Commission Act, and the Massachusetts Coastal Zone Management program. These legal violations are additional reasons that the permit application must be denied.

THERE ARE SIGNIFICANT PROCEDURAL DEFICIENCIES UNDER THE NATIONAL ENVIRONMENTAL POLICY ACT (NEPA)

There are numerous federal and state law procedural deficiencies that afflict the Corps' review of the proposed project. The DEIS is insufficient because the applicant has played an improper role in virtually every aspect of the NEPA process; the DEIS is not objective; the Corps has failed to conduct a programmatic EIS; the DEIS relies on inadequate and incomplete data; and the DEIS fails to consider the proper state boundaries.

THE ALTERNATIVES ANALYSIS IS INADEQUATE

The DEIS fails to review alternatives adequately. It does not establish an appropriate EIS purpose and need statement, uses an illegally constrained alternatives review, and fails to identify and adequately address project impacts.

The DEIS purpose and need statement is crafted narrowly to advance the applicant's profit-making goals, not the public interest, and violates NEPA. The Corps' overly restrictive purpose and need statement compromises the entire review of the CWA project and invalidates the DEIS. The narrow terms of that statement, particularly the limitation of a "utility-scale renewable facility (200 MW or larger)" designed to deliver electricity solely to "the New England grid" are intended to produce a specific result, i.e., approval of the applicant's preferred alternative on Horseshoe Shoal. In fact, the record of power projects in New England demonstrates that there is no basis for equating the "utility scale" limitation with 200 MW; the record for such projects in New England is 20 MW. This is the threshold used by the American Wind Energy Association. By impermissibly restricting purpose and need, the Corps also has limited the review of alternatives to only a very few sites and only one technology.

The DEIS fails to consider any technology other than wind in any area other than the immediate vicinity of Nantucket Sound. Such an approach violates NEPA.

The Corps' alternative analysis is further invalidated by the improper screening criteria used to identify alternatives. With respect to project risk, the Corps does not account for the differential risk of onshore wind versus offshore wind. Most of the wind projects in the world are onshore. Onshore technology is an established and reliable technology, whereas offshore technology is much less mature and is still evolving.

The criteria used by the Corps are applied without regard to trade-offs that exist between different elements of the criteria. For example, land-based sites can often be economic with less wind than offshore, yet the same wind class screen is used for both.

The Corps criteria also do not consider the issue of economic viability. Failed plants are not in the public interest. Thus, the Corps needs to review the developer's financial plan for the project sufficiently to ensure that the project is viable. This is particularly relevant since there is such a large inventory of projects that, while not bankrupt, are sufficiently non-performing that their owners have turned them over to the bank. The public has a right to know this information and comment on it especially since a public trust resource is at stake.

A second aspect of economic viability deals with the issue of what happens in the event the plant needs to be removed, either as a result of a premature event or at the end of its useful life. The Corps must ensure that the developer has made separate arrangements so that when and if the plant needs to be dismantled, there are sufficient funds to do this, which were separate from the funds related to building and operating the plant.

The screening criteria also are flawed because they rely upon outdated information on transmission capacity and make false assumptions on the nature of purported "bottlenecks" in the system.

By failing to use a valid set of screening criteria, the Corps did not consider at least eight alternative sites, still under the unlawfully narrow purpose and need statement of the DEIS. These sites easily fit within NEPA requirements for reasonable alternatives, and the failure to account for them renders the DEIS invalid.

If a proper purpose and need statement is developed--to provide a feasible utility-scale, clean energy project (i.e., greater than 20 MW) within the Northeast (Canada/United States) and Mid-Atlantic region, for which the public interest advantages outweigh the costs to the public interest--a reasonable set of alternatives would be identified. These alternatives include offshore wind projects (including deepwater sites that would be available before there is a regional energy need), onshore wind projects, other forms of renewable energy, and clean energy projects that provide substantially similar or better benefits for the public.

THE WIND ENERGY PLANT WILL DESTROY THE SANCTUARY STATUS AND MARINE PROTECTED AREA VALUES OF NANTUCKET SOUND

All state waters within Nantucket Sound are designated as a marine sanctuary under State law. The purpose of that designation is to protect the very values of the Sound that would be destroyed by the project, including its scenery and overall ecology. The unique nature of the Sound also has caused it to be placed on the list of areas for consideration as a federal marine sanctuary. The designation of the state waters qualifies the entire Sound for MPA status under Presidential Executive Order 13158. For the Corps to comply with that Order, it would have to deny this permit application because it will cause harm to the protected values of the Cape and Islands Ocean Sanctuary.

The DEIS is deeply flawed in its complete failure to address the special status of Nantucket Sound as: a sanctuary under State law; an area that meets the federal definition of an MPA; and an area that is subject to National Marine Sanctuary review. This failure leaves the Sound vulnerable to projects like this one, which will destroy the very values that give the Sound these features deserving of protection. This failure is especially inappropriate, since it is possible to have *both* under a proper decision-making process: protected status for the Sound, and offshore wind in properly-sited locations.

NEITHER THE CORPS NOR CAPE WIND HAS ADDRESSED THE CLARIFIED STATE BOUNDARIES

It has now been announced that the Massachusetts boundary extends into the project site. This is a self-executing, factual determination that carries with it full Massachusetts regulatory jurisdiction and the State's power plant prohibition in marine sanctuaries. It also makes the lands and waters within the clarified boundary part of the Cape and Island Ocean Sanctuary. These are major charges that both the Corps and CWA knew were forthcoming, yet the DEIS is silent on the issue. The failure to address the application of Massachusetts jurisdiction to this project requires a supplemental EIS.

THE DEIS IS FILLED WITH TECHNICAL DEFICIENCIES

The Alliance commissioned over 30 technical consultants to review the DEIS. In the short, and inadequate, public review period provided by the Corps for the multivolume DEIS, these consultants developed over 400 pages of comments on the deficiencies of the document. The message of these comments is clear: the DEIS is a result-oriented, technically deficient review that does not meet professional or legal standards. Further review of the CWA proposal therefore requires a supplemental EIS.

Adams, Karen K NAE

From: William Reyelt [williamreyelt@hotmail.com]
Sent: Thursday, February 24, 2005 6:32 PM
To: Energy, Wind NAE
Cc: williamreyelt@hotmail.com
Subject: Cape Wind DEIS Comments

Reyelt_Comments_DEIS.DOC

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February 24, 2005

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RE: Comment on Cape Wind DEIS

Dear Ms. Adams:

Thank you for the opportunity to submit comments on the Cape Wind Draft Environmental Impact Statement (DEIS).

First, I would like to thank the Army Corps of Engineers for all the effort is has put into the DEIS and the project's review process thus far. I believe that the DEIS has accomplished a great deal with respect to dispelling many of the objections and myths presented by those who oppose the project.

In my mind, the significance of this project is difficult to understate. Beyond the project itself and its potential health, environmental and economic benefits, the future of Cape Wind is the bellweather that will indicate whether or not Massachusetts and, perhaps by extension, the United States have the will and foresight to confront our civilization's most daunting challenges. While the worldwide effects of climate change and the growing scarcity of cheap energy are only beginning to be acknowledged, this one-two punch will have indesputeably dramatic impacts on the newest generation of children and the quality of their lives.

I imagine that many comments have emphasized Cape Wind's important environmental benefits. While I fully concur with that emphasis, I would like use my comments to stress the importance of Cape Wind's perhaps more immediate benefit to our region's energy stability and economic future. It is hard to turn on the television news or read a newspaper without hearing of the economic challenges that we face both regionally and nationally. I ask that the FEIS further explore and contrast the region's economic future with and without the incremental increase in energy independence provided by Cape Wind. Today's competitive global economy, and that of the United States in particular, is a house of cards built on a foundation of cheap, abundant energy. In the U.S., our almost total reliance on fossil fuels as the infrastructure of our economy is our Achilles heel. The longer that we delay in diversifying our energy sources, the more dramatically our economy, a critical component of our livelihood, will come to its knees.

Massachusetts has long been a national leader in environmental protection, business innovation and a host of other areas. Cape Wind is perhaps our most significant recent opportunity to again demonstrate that leadership. Too many of our political leaders are ducking their responsibility to lead and, instead, pandering to short sighted, subjective, parochial concerns about visual impacts. I am grateful to the AcoE for objective and independent assessment of the positive and negative impacts of the Cape Wind proposal To facilitate facilitate this important opportunity for the Commonwealth and provide an even more thoughtful assessment, it is critical that the FEIS further analyze the region's energy and economic future with and without Cape Wind. Our ability to move toward energy independence through local and sustainable production will be perhaps the most critical element to maintaining economic vitality and quality of life over the next century.

In addition to the importance of Cape Wind relative to our energy supply and associated economic future, I ask that the FEIS provide additional analysis of the existing negative visual impacts on Nantucket Sound. While the sight of spinning windmills generating clean energy from a free and abundant source is one that fills me with desperately needed hope for our long-term well being and that of my infant daughter, much has been made of the potentially negative visual impact that Cape Wind will have for those who will view it as a blight on the landscape. For me, the sight of bulbous, often ostentatious, fuel-hungry powerboats and boxy, vinyl-sided motels significantly detracts from the otherwise natural beauty of Nantucket Sound. The DEIS provides a survey of historically significant sights within visual range of the project, but could also provide, as a means of perspective, a survey of existing man-made visual disruptions to the natural setting. What public benefit do these existing visual disruptions have and how do their benefits compare to that of Cape Wind? If nothing else, my point here is that the visual impact of the windmills is tremendously subjective and for many of us I suspect that they will represent a kinetic vision of hope. And hope is beauty.

In closing I would like to say that I am fortunate to share a family home on Nantucket with my siblings and their families. Over the past twenty plus years I have regularly enjoyed summers on Nantucket. Far from dampening my urge to spend time on the island, the site of Cape Wind will undoubtedly be a nourishing one for me. While we do not have an ocean view, Steps Beach is a short, five-minute walk from our house. I look forward to the prospect of someday making that familiar walk with my now nine-month old daughter and being able to point her to a premiere example of human ingenuity and the will in the face of great adversity.

Sincerely,

Bill Reyelt

cc: Governor Mitt Romney
U.S. Senator Ted Kennedy
U.S. Senator John Kerry
State Attorney General Thomas Reilly

State Senator Diane Wilkerson
State Representative Elizabeth Malia
Anne Canady, MEPA
Cape Cod Commission

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Cape Cod Commission

February 24, 2005

4393

Re: Cape Wind Environmental Review

To the Army Corps of Engineers

I submit the following statement and accompanying documents to the Army Corps of Engineers for your consideration for inclusion as additional documentation of the extremely important environmental and health benefits which will result from its approval and ultimate completion. The DEIS for Cape Wind does not, in my opinion, adequately recognize the full danger to Massachusetts and the global biosphere resulting from fossil fuel generated carbon dioxide emissions contributing to accelerated global warming, and by accompanying particulates and gases including NOx, Sox and VOCs. Several recent studies are referenced and enclosed.

The first predicts likely worsening of ground level ozone in the Northeast with expected climate warming,

Cape Wind turbines and wind farm will not contribute significantly to global warming due to fossil fuel use. Thus it would have this additional predicted benefit of not contributing to global warming nor increased stagnant pollution air episodes during summers. Its approval will help facilitate future renewable wind energy projects. Defeat of Cape Wind will subject the region to further use of fossil fuel generation and concomitant climate warming and increased regional air pollution with associated morbidity and mortality increases due to direct and indirect toxic effects of fossil fuel emissions among humans, flora and fauna. Viz:

Effects of Future Climate Change on Regional Air Pollution Episodes in the United States, Mickley et al., Geophysical Research Letters, 2004. See Boston Sunday Globe article below.

The second are two articles new scientific report estimates the toll in cardiovascular morbidity and mortality associated with particulate air pollution and finds the effects significant in loss of human life and disease causation. One must assume, until proven otherwise, that other mammals if not all mammals in Massachusetts and New England would also benefit from cleaner air through this same mechanism. Cape Wind turbines and wind farm will not contribute significantly to this local or regional air pollution or their resulting harms.

Ambient air pollution and atherosclerosis in Los Angeles, Kunzli et al, Environmental Health Perspectives, November 2004 and

Cardiovascular Mortality and Long Term Exposure to Particulate Air Pollution, Pope et al., Circulation, January, 2004.

The third article is associated with new research which has greatly heightened the concern of international climate scientists. A massive research project using donated volunteer computing power from a large array of home and desktop computers has generated a new estimate of the forcing sensitivity of the global climate in response to a doubling of carbon dioxide. The results from the ClimatePrediction.Net research, published in Nature January 5, 2005 finds that the climate system is much more sensitive to carbon dioxide forcing than previously estimated by previous researchers. The implication of this finding is that the climate system is much more sensitive to perturbation and thus the risk of an abrupt or extreme response of the climate system is ever more likely. Such a major disruption to the climate signifies much greater risk to the global and of course our regional environment. Rapid sea level rise and serious alterations in the thermohaline circulation with resulting paradoxical cooling of the Northeast US and Western Europe becomes more conceivable. Viz:

Uncertainty in predictions of the climate response to rising levels
D. A. Stainforth et al, NATURE | VOL 433 | 27 JANUARY 2005.

A fourth finding is a recent report by the British Antarctic Survey that ominous signs of melting and other destabilizing changes appear to be developing on the West Antarctic Ice Sheet, something which had not been anticipated this soon in the evolution of global warming. See accompanying article from The Independent. Viz:

West Antarctic Ice Sheet Shows Early Signs of Disintegration
Dramatic change in West Antarctic ice could produce 16ft rise in sea levels
The Independent (UK), Feb. 2, 2005

Lastly, the new head of the IPCC whose appointment had been promoted by the Bush administration has recently declared that carbon dioxide levels in the atmosphere had reached a dangerous level. Viz:

Pachauri: Climate Approaching Point of "No Return"
Global Warming Approaching Point of No Return, Warns Leading Climate Expert
The Independent (U.K.), Jan. 23, 2005

He and other prominent scientists are calling for strict and rapid reductions in carbon emissions; the ranks of scientists calling for an upper limit of 400 or 450 ppd of CO2 by the end of this century is increasing. The Cape Wind project is a necessary first step for Massachusetts, New England and the United States to promote rapid transition to clean renewable wind energy for the purpose of protecting our global environment, our biosphere's stability, our health, our economy and our future.

Yours truly,

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Enclosure & attachments.

Boston Sunday Globe, February 20, 2005, p. A-15

Warming world could worsen pollution in Northeast, Midwest
Harvard researcher to report at AAAS meeting on projected decline in cleansing summer winds

Source: Copyright 2005,
Date: February 19, 2005

CAMBRIDGE, Mass. -- While science's conventional wisdom holds that pollution feeds global warming, new research suggests that the reverse could also occur: A warming globe could stifle summer's cleansing winds over the Northeast and Midwest over the next 50 years, significantly worsening air pollution in these regions.

Loretta J. Mickley, a research associate at Harvard University's Division of Engineering and Applied Sciences, will report on these findings Saturday, Feb. 19, at the annual meeting of the American Association for the Advancement of Science in Washington, D.C. Her work is based on modeling of the impact of increasing greenhouse gas concentrations on pollution events across the United States through 2050.

Using this model, Mickley and colleagues found that the frequency of cold fronts bringing cool, clear air out of Canada during summer months declined about 20 percent. These cold fronts, Mickley said, are responsible for breaking up hot, stagnant air that builds up regularly in summer, generating high levels of ground-level ozone pollution.

"The air just cooks," Mickley says. "The pollution accumulates, accumulates, accumulates, until a cold front comes in and the winds sweep it away."

Ozone is beneficial when found high in the atmosphere because it absorbs cancer-causing ultraviolet radiation. Near the ground, however, high concentrations are considered a pollutant, irritating sensitive tissues, particularly lung tissues.

"If this model is correct, global warming would cause an increase in difficult days for those affected by ozone pollution, such as people suffering with respiratory illnesses like asthma and those doing physical labor or exercising outdoors," Mickley says.

Mickley and her colleagues used a complex computer model developed by the Goddard Institute for Space Studies in New York, with further changes devised by her team at Harvard. It takes known elements such as the sun's luminosity, the earth's topography, the distribution of the oceans, the pull of gravity and the tilt of the earth's axis, and figures in variables provided by researchers.

Mickley gradually increased levels of greenhouse gases at rates projected by the Intergovernmental Panel on Climate Change, a group charged by the United Nations to study future climate variation. Her model looked at the effect the changing climate would have on the concentrations of two pollutants: black carbon particles -- essentially soot -- and carbon monoxide, which could also indicate ozone levels. When the model first indicated that future climate change would lead to higher pollution in the Northeast and Midwest, Mickley and her colleagues were a bit surprised.

"The answer lies in one of the basic forces that drive the Earth's weather: the temperature difference between the hot equator and the cold poles," Mickley says.

Between those extremes, the atmosphere acts as a heat distribution system, moving warmth from the equator toward the poles. Over mid-latitudes, low-pressure systems and accompanying cold fronts are one way for heat to be redistributed. These systems carry warm air poleward ahead of fronts and draw down cooler air behind fronts.

In the future, that process could slow down. As the globe warms, the poles are expected to warm more quickly than the equator, decreasing the temperature difference between the poles and the equator. The atmosphere would then have less heat to redistribute and would generate fewer low-pressure systems.

With fewer cold fronts sweeping south to break up hot stagnant air over cities, the air would sit in place, gathering pollutants. Mickley's model shows the length of these pollution episodes would increase significantly, even doubling in some locations.

Mickley's collaborators include Daniel J. Jacob and B. D. Field at Harvard and D. Rind of the Goddard Institute for Space Studies.

For Additional Information:
(may become dated as article ages)

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Uncertainty in predictions of the climate response to rising levels of greenhouse gases

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The range of possibilities for future climate evolution[1–3] needs to be taken into account when planning climate change mitigation and adaptation strategies. This requires ensembles of multi-decadal simulations to assess both chaotic climate variability and model response uncertainty[4–9]. Statistical estimates of model response uncertainty, based on observations of recent climate change[10–13], admit climate sensitivities—defined as the equilibrium response of global mean temperature to doubling levels of atmospheric carbon dioxide—substantially greater than 5 K. But such strong responses are not used in ranges for future climate change[14] because they have not been seen in general circulation models. Here we present results from the 'climate*prediction*.net' experiment, the first multi-thousand-member grand ensemble of simulations using a general circulation model and thereby explicitly resolving regional details[15–21]. We find model versions as realistic as other state-of-the-art climate models but with climate sensitivities ranging from less than 2 K to more than 11 K. Models with such extreme sensitivities are critical for the study of the full range of possible responses of the climate system to rising greenhouse gas levels, and for assessing the risks associated with specific targets for stabilizing these levels.

As a first step towards a probabilistic climate prediction system we have carried out a grand ensemble (an ensemble of ensembles) exploring uncertainty in a state-of-the-art model. Uncertainty in model response is investigated using a perturbed physics ensemble[4] in which model parameters are set to alternative values considered plausible by experts in the relevant parameterization schemes[9]. Two or three values are taken for each parameter (see Methods); simulations may have several parameters perturbed from their standard model values simultaneously. For each combination of parameter values (referred to here as a 'model version') an initial-condition ensemble[22] is used, creating an ensemble of ensembles. Each individual member of this grand ensemble (referred to here as a 'simulation') explores the response to changing boundary conditions[22] by including a period with doubled CO_2 concentrations.

The general circulation model (GCM) is a version of the Met Office Unified Model consisting of the atmospheric model HadAM3[23], at standard resolution[9] but with increased numerical stability, coupled to a mixed-layer ocean. This allows us to explore the effects of a wide range of uncertainties in the way the atmosphere is represented, while avoiding a long spin-up for each model version. Each simulation involves three 15-year phases: (1) calibration, to deduce the ocean heat-flux convergence field used in the subsequent phases; (2) control, used to quantify the relevance of the particular model version and heat-flux convergence field; and (3) doubled CO_2, to explore the response to changing boundary conditions.

Individual simulations are carried out using idle processing capacity on personal computers volunteered by members of the general public[19]. This distributed-computing method[16,18,19] leads to a continually expanding data set of results, requiring us to use a specified subset of data available at a specific point in time. The analysis presented here uses 2,578 simulations (>100,000 simulated years), chosen to explore combinations of perturbations in six parameters.

The 2,578 simulations contain 2,017 unique simulations (duplicates are used to verify the experimental design—see Methods). Figure 1a shows the grand ensemble frequency distribution of global mean, annual mean, near-surface temperature (T_g) in these 2,017 simulations, as it develops through each phase. Some model versions show substantial drifts in the control phase owing to the use of a simplified ocean (see Supplementary Information). We remove unstable simulations (see Methods) and average over initial-condition ensembles of identical model versions to reduce sampling uncertainty. The frequency distribution of initial-condition-ensemble-mean time series of T_g for the resulting 414 model versions (for which the initial-condition ensembles involve 1,148 independent stable simulations) is shown in Fig. 1b. Six of these model versions show a significant cooling tendency in the doubled-CO_2 phase. This cooling is also due to known limitations with the use of a simplified ocean (see Supplementary Information) so these simulations are excluded from the remaining analysis of sensitivity.

The frequency distribution of the simulated climate sensitivities (see Methods) for the remaining model versions is shown in Fig. 2a and ranges from 1.9 to 11.5 K. Two key features are that relatively few model versions have sensitivities less than 2 K, and the long tail of the distribution extending to very high values; 4.2% are >8 K. Most sensitivities cluster round 3.4 K, the value for the unperturbed model, suggesting that many of the parameter combinations

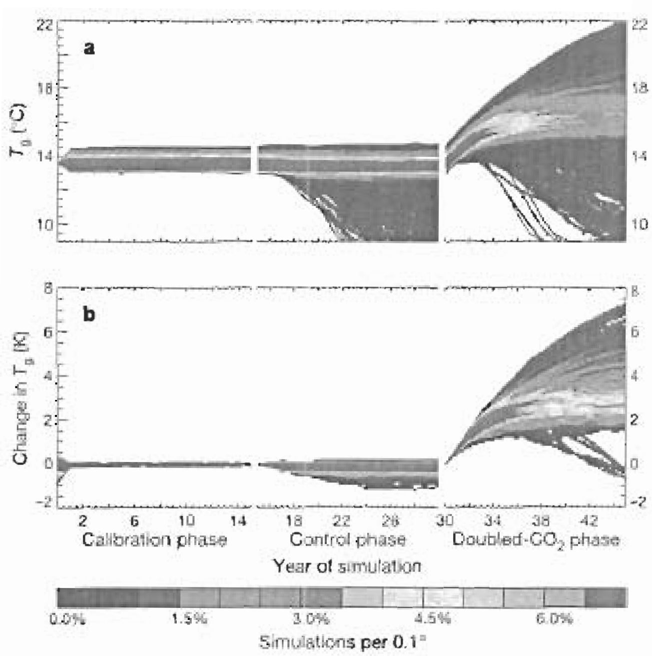

Figure 1 Frequency distributions of T_g (colours indicate density of trajectories per 0.1 K interval) through the three phases of the simulation. **a**, Frequency distribution of the 2,017 distinct independent simulations. **b**, Frequency distribution of the 414 model versions. In **b**, T_g is shown relative to the value at the end of the calibration phase and where initial-condition ensemble members exist, their mean has been taken for each time point.

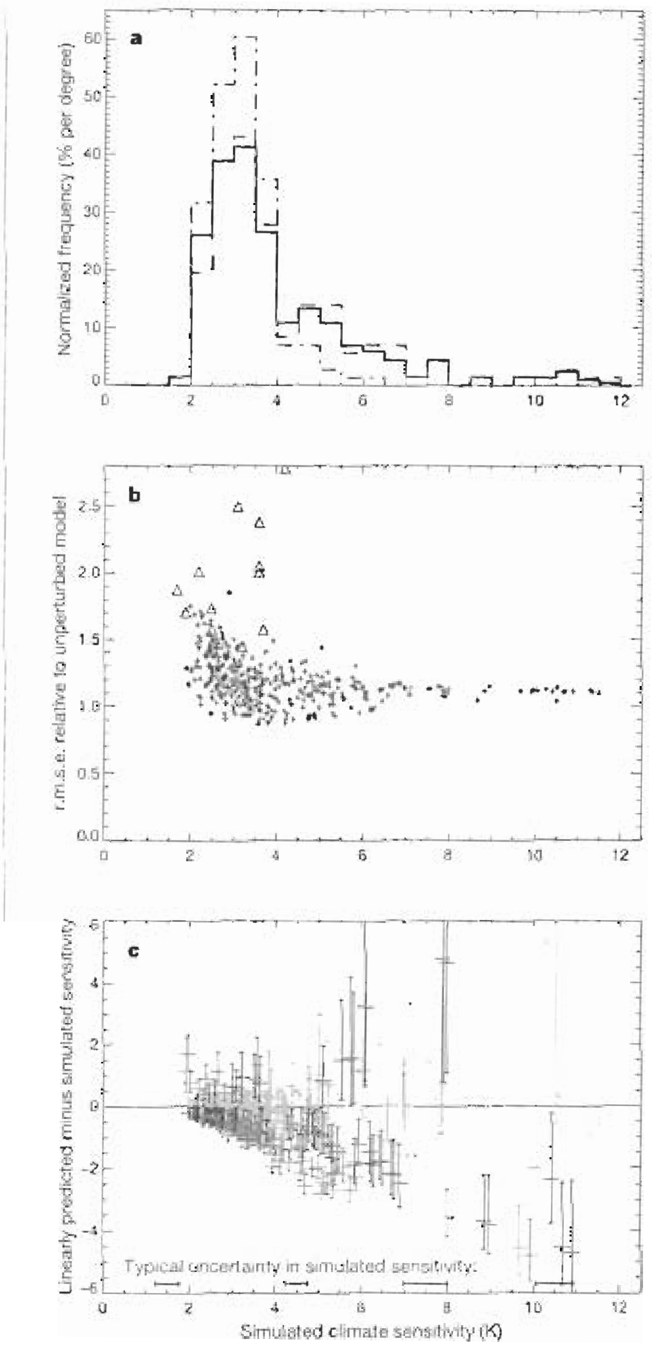

Figure 2 The response to parameter perturbations. **a**, The frequency distribution of simulated climate sensitivity using all model versions (black), all model versions except those with perturbations to the cloud-to-rain conversion threshold (red), and all model versions except those with perturbations to the entrainment coefficient (blue). **b**, Variations in the relative r.m.s.e. of model versions. The unperturbed model is shown by the red diamond. Model versions with only a single parameter perturbed are highlighted by yellow diamonds. The triangles show the CMIP II models for which data are available; HadCM3 (having the same atmosphere as the unperturbed model but with a dynamic ocean) is shown in red and the others in blue. **c**, Linear prediction of climate sensitivity based on summing the change in λ for the relevant single-parameter-perturbation model versions, to estimate λ when multiple perturbations are combined. Error bars show the resulting uncertainty ($\pm$ one sigma) caused by the combination of a number of $\Delta\lambda$ values where each λ has an uncertainty deduced from the initial-condition ensembles having only a single parameter perturbed. Linear predictions within one sigma of the simulated value are shown in green, between one and two sigma in black, and above two sigma in red. Mean uncertainties in the simulated value (two-sigma range, inferred from the initial-condition ensembles) are shown at the bottom for four regions of sensitivity (0–3, 3–6, 6–9, 9–12).

explored have relatively little effect on this global variable. There are a number of possible reasons for this clustering: the relevant processes may in fact have only a limited impact on sensitivity, the parameter ranges used may be too small to influence substantially the response in this model, and/or multiple perturbations may have mutually compensating effects when averaged on global scales. Of course, many significant regional impacts are invisible in a global average.

The range of sensitivities across different versions of the same model is more than twice that found in the GCMs used in the IPCC Third Assessment Report[14]. The possibility of such high sensitivities has been reported by studies using observations to constrain this quantity[9,11,24,25], but this is the first time that GCMs have generated such behaviour. The shape of the distribution is determined by the parameters selected for perturbation and the perturbed values chosen, which were relatively arbitrary. Model developers provided plausible high and low values for each model parameter; however, we cannot interpret these as absolute upper and lower bounds because experts are known to underestimate uncertainty even in straightforward elicitation exercises where the import of the question is clear[26]. In our case even the physical interpretation of many of these parameters is ambiguous[17]. We can illustrate the importance of the parameter choices by subsampling the model versions. If all perturbations to one parameter (the cloud-to-rain conversion threshold) are omitted, the red histogram in Fig. 2a is obtained, with a slightly increased fraction (4.9%) of model versions >8 K. If perturbations to another parameter (the entrainment coefficient) are omitted, the blue histogram in Fig. 2a is obtained, with no model versions >8 K. (See Supplementary Information for further sensitivity analyses.)

Can either high-end or low-end sensitivities be rejected on the basis of the model-version control climates? Fig. 2b suggests not; it illustrates the relative ability of model versions to simulate observations using a global root-mean-squared error (r.m.s.e.) normalized by the errors in the unperturbed model (see Methods). For all model versions this relative r.m.s.e. is within (or below) the range of values for other state-of-the-art models, such as those used in the second Coupled Model Inter Comparison (CMIP II) project[28] (triangles). The five variables used for this comparison are each standard variables in model evaluation and inter-comparison exercises[29] (see Methods). This lack of an observational constraint, combined with the sensitivity of the results to the way in which parameters are perturbed, means that we cannot provide an objective probability density function for simulated climate sensitivity. Nevertheless, our results demonstrate the wide range of behaviour possible within a GCM and show that high sensitivities cannot yet be neglected as they were in the headline uncertainty ranges of the IPCC Third Assessment Report (for example, the 1.4–5.8 K range for 1990 to 2100 warming).[14] Further, they tell us about the sensitivities of our models, allowing better-informed decisions on resource allocation both for observational studies and for model development.

Can we coherently predict the model's response to multiple parameter perturbations from a small number of simulations each of which perturbs only a single parameter[9]? The question is important because it bears on the applicability of linear optimization methods in the design and analysis of smaller ensembles. Figure 2c shows that assuming that changes in the climate feedback parameter[13] λ combine linearly provides some insight, but fails in two important respects. First, combining uncertainties gives large fractional uncertainties for small predicted λ and hence large uncertainties for high sensitivities. This effect becomes more pronounced the greater the number of parameters perturbed. Second, this method systematically underestimates the simulated sensitivity, as shown in Fig. 2c, and consequently artificially reduces the implied likelihood of a high response. Furthermore, more than 20% of the linear predictions are more than two standard errors from the simulated sensitivities. Thus, comprehensive multiple-perturbed-parameter ensembles appear to be necessary for robust probabilistic analyses.

Figure 3 shows the initial-condition ensemble-mean of the temperature and precipitation changes for years 8–15 after doubling CO_2 concentrations, for three model versions: (1) the unperturbed model; (2) a version with low sensitivity; and (3) a version with high sensitivity (see Supplementary Information for details of the control climates in these model versions). All three models show the familiar increased warming at high latitudes and the overall surface-temperature pattern scales with sensitivity. Even in the low-sensitivity model version the warming in certain regions is substantial, exceeding 3 K in Amazonia and 4 K in much of North America. The precipitation field shows a greater variety of response. For instance, this particular low-sensitivity model version shows a region of substantially reduced precipitation east of the Mediterranean; something not evident in either the standard or high-sensitivity model versions shown. It is critical to note that model versions with similar sensitivities often also show differences in such regional details[9]. The use of a GCM-based grand ensemble allows the significance of such details to be ascertained.

Thanks to the participation and enthusiasm of tens of thousands of individuals world-wide we have been able to discover GCM versions with comparatively realistic control climates and with sensitivities covering a much wider range than has ever been seen before. These results are a critical step towards a better under-

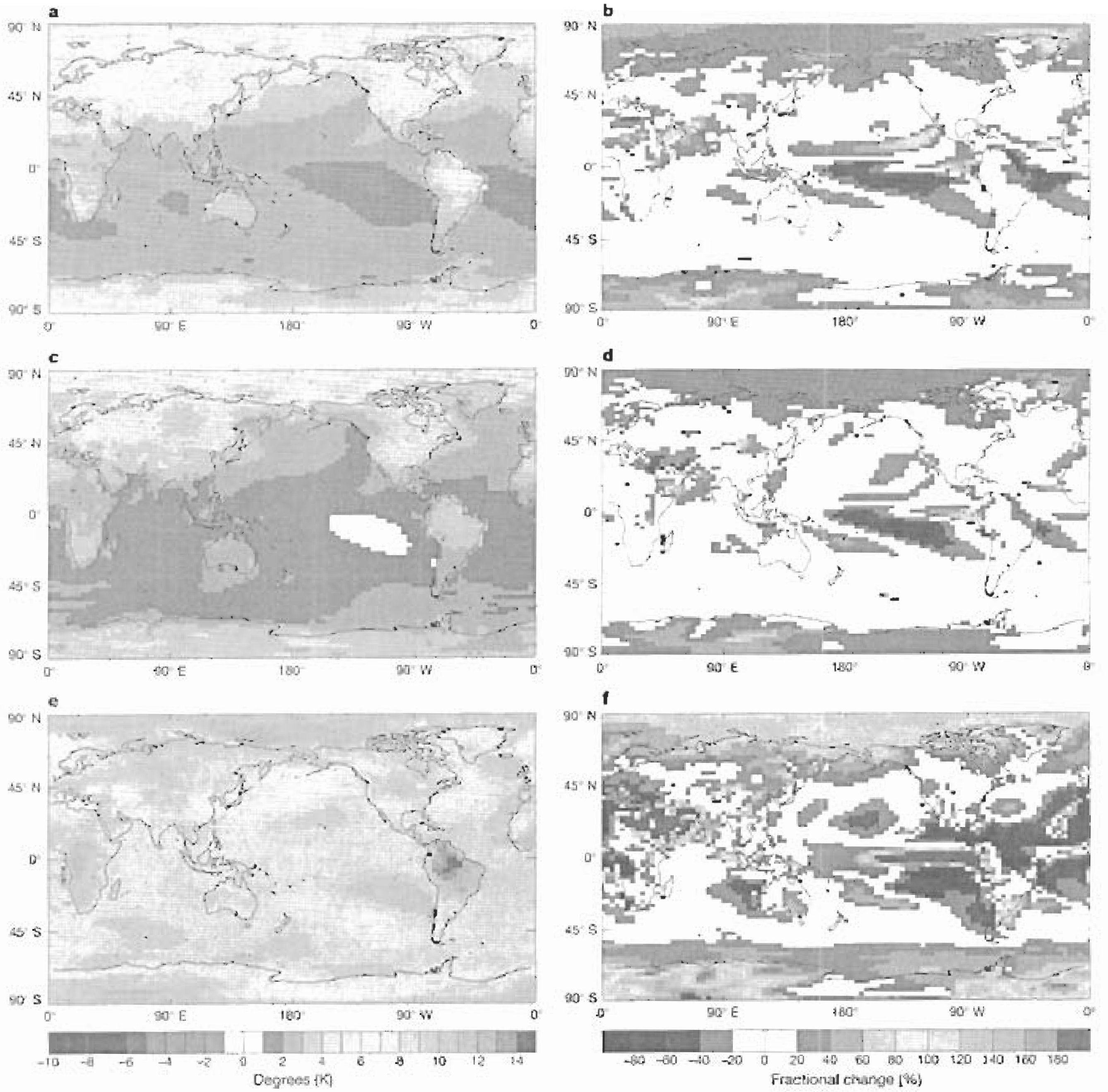

Figure 3 The temperature (left panels) and precipitation (right panels) anomaly fields in response to doubling the CO_2 concentrations. **a**, **b**, The unperturbed model (simulated climate sensitivity, 3.4 K). **c**, **d**, A model version with low simulated climate sensitivity (2.5 K). **e**, **f**, A model version with high simulated climate sensitivity (10.5 K). These fields are the means of years eight to fifteen after the change of forcing is applied, averaged over initial-condition ensemble members; they are not the equilibrium response.

standing of the potential responses to increasing levels of greenhouse gases, regional and seasonal impacts, our models and internal variability. Future experiments will include a grand ensemble of transient simulations of the years 1950–2100 using a model with a fully dynamic ocean. □

Methods

Model simulations

Participants in the climate*prediction*.net experiment download an executable version of a full GCM. They are allocated a particular set of parameter perturbations and initial conditions enabling them to run one simulation: that is, one member of the grand ensemble. Their personal computer then carries out 45 years of simulation and returns results to the project's servers. Over 90,000 participants from more than 140 countries have registered to date. The model, based on HadSM3[30], is a climate resolution version of the Met Office Unified Model with the usual horizontal grid of 3.75° longitude × 2.5° latitude and 19 layers in the vertical. The ocean consists of a single thermodynamic layer with ocean heat transport prescribed using a heat-flux convergence field that varies with position and season but has no inter-annual variability. For each simulation the heat-flux convergence field is calculated in the calibration phase where sea surface temperatures (SSTs) are fixed; in subsequent phases the SSTs vary according to changes in the atmosphere–ocean heat flux. The initial-condition ensemble members have different starting conditions for the calibration and therefore allow for uncertainty in the heat-flux convergence fields used in the control and doubled-CO_2 phases.

Data quality

Most model simulations are unique members of the grand ensemble, each being a combination of perturbed model parameters and perturbed initial conditions. To evaluate the reliability of the experimental design a certain number of identical simulations are distributed; most give identical results. Where they do not, they are usually very similar, suggesting that a few computational bits were lost at some point and consequently they are essentially different members of the initial-condition ensemble. In these cases the mean of the simulations is taken.

There are a small number of simulations (1.6%) which show obvious flaws in the data: for example, sudden jumps of data values from of the order of 10^2 to of the order of 10^8. These probably result from loss of information, for instance during a PC shut-down at a critical point in processing or a result of machine 'overclocking'. These are removed from this analysis. Finally, runs that show a drift in T_g greater than 0.02 K yr^{-1} in the last eight years of the control are judged to be unstable and are also removed from this analysis.

Perturbations

Perturbations are made to six parameters, chosen to affect the representation of clouds and precipitation: the threshold of relative humidity for cloud formation, the cloud-to-rain conversion threshold, the cloud-to-rain conversion rate, the ice fall speed, the cloud fraction at saturation and the convection entrainment rate coefficient. This is a subset of those explored by ref. 9. In each model version each parameter takes one of three values (the same values as those used by ref. 9); for cloud fraction at saturation only the standard and intermediate values are used. As climate*prediction*.net continues, the experiment is exploring 21 parameters covering a wider range of processes and values.

Climate sensitivity calculations

The simulated climate sensitivity is taken as the difference between the predicted equilibrium T_g in the doubled-CO_2 and control phases. The latter is simply the mean of the last eight years of that phase. The former is deduced by fitting the change in T_g, relative to the start of the phase, to the exponential expression: $\Delta T_g(t) = \Delta T_{g\,(2\times CO2)}(1 - \exp(-t/\tau))$, giving us a value of $T_{g\,(2\times CO2)}$ that allows for uncertainty in the response timescale, τ. Even for high simulated climate sensitivities the uncertainty in this procedure is small (see Fig. 2c) and alternative methods give similar results. Because it is based on the first 15 years' response, the λ associated with this simulated climate sensitivity reflects the decadal timescale feedbacks in the system. Longer, centennial-timescale processes could affect the ultimate value of the equilibrium sensitivity and are best studied using models with dynamic oceans and cryospheres.

Relative root-mean-square error

Models are compared with gridded observations of annual mean temperature, sea level pressure, precipitation and atmosphere–ocean sensible and latent heat flux. The total error in variable j is defined simply as:

$$\varepsilon_{js}^2 = (\Sigma_i w_i(m_{is} - o_i))^2 \qquad (1)$$

where m_{is} is the simulated value in grid-box i averaged over the last 8 yr of the control phase of simulation s, o_i is the observed value[9] and w_i is an area weighting. Mean squared errors relative to the standard model are computed as:

$$\varepsilon_s^2 = (\Sigma_j \varepsilon_{js}^2 / \varepsilon_{ju}^2)/N \qquad (2)$$

where N is the number of variables and ε_{ju}^2 is the mean ε_{js}^2 for the unperturbed model, and averaged across initial-condition ensembles. Normalizing errors in individual variables by the corresponding errors in the unperturbed model ensures that all variables are given equal weight. The relative r.m.s.e. is plotted in Fig. 2b. Note that because we do not have an explicit and adequate noise model (ε_{js}^2 does not account for correlations, for example), these 'scores' cannot be interpreted explicitly in terms of likelihood, but nevertheless provide an indication of the relative merits of different model control climates.

For the CMIP II data the $(m_i - o_i)^2$ term is reduced by the variance of the mean to compensate for the greater variability found in models with dynamic oceans.

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Pachauri: Climate Approaching Point of "No Return"
Global Warming Approaching Point of No Return, Warns Leading Climate Expert

The Independent (U.K.), Jan. 23, 2005

Global warning has already hit the danger point that international attempts to curb it are designed to avoid, according to the world's top climate watchdog.

Dr Rajendra Pachauri, the chairman of the official Intergovernmental Panel on Climate Change (IPCC), told an international conference attended by 114 governments in Mauritius this month that he personally believes that the world has "already reached the level of dangerous concentrations of carbon dioxide in the atmosphere" and called for immediate and "very deep" cuts in the pollution if humanity is to "survive".

His comments rocked the Bush administration - which immediately tried to slap him down - not least because it put him in his post after Exxon, the major oil company most opposed to international action on global warming, complained that his predecessor was too "aggressive" on the issue.

A memorandum from Exxon to the White House in early 2001 specifically asked it to get the previous chairman, Dr Robert Watson, the chief scientist of the World Bank, "replaced at the request of the US". The Bush administration then lobbied other countries in favour of Dr Pachauri - whom the former vice-president Al Gore called the "let's drag our feet" candidate, and got him elected to replace Dr. Watson, a British-born naturalised American, who had repeatedly called for urgent action.

But this month, at a conference of Small Island Developing States on the Indian Ocean island, the new chairman, a former head of India's Tata Energy Research Institute, himself issued what top United Nations officials described as a "very courageous" challenge.

He told delegates: "Climate change is for real. We have just a small window of opportunity and it is closing rather rapidly. There is not a moment to lose."

Afterwards he told The Independent on Sunday that widespread dying of coral reefs, and rapid melting of ice in the Arctic, had driven him to the conclusion that the danger point the IPCC had been set up to avoid had already been reached.

Reefs throughout the world are perishing as the seas warm up: as water temperatures rise, they lose their colours and turn a ghostly white. Partly

as a result, up to a quarter of the world's corals have been destroyed.

And in November, a multi-year study by 300 scientists concluded that the Arctic was warming twice as fast as the rest of the world and that its ice-cap had shrunk by up to 20 per cent in the past three decades.

The ice is also 40 per cent thinner than it was in the 1970s and is expected to disappear altogether by 2070. And while Dr. Pachauri was speaking, parts of the Arctic were having a January "heatwave", with temperatures eight to nine degrees centigrade higher than normal.

He also cited alarming measurements, first reported in The Independent on Sunday, showing that levels of carbon dioxide (the main cause of global warming) have leapt abruptly over the past two years, suggesting that climate change may be accelerating out of control.

He added that, because of inertia built into the Earth's natural systems, the world was now only experiencing the result of pollution emitted in the 1960s, and much greater effects would occur as the increased pollution of later decades worked its way through. He concluded: "We are risking the ability of the human race to survive."

West Antarctic Ice Sheet Shows Early Signs of Disintegration
Dramatic change in West Antarctic ice could produce 16ft rise in sea levels

The Independent (UK), Feb. 2, 2005

British scientists have discovered a new threat to the world which may be a result of global warming. Researchers from the Cambridge-based British Antarctic Survey (BAS) have discovered that a massive Antarctic ice sheet previously assumed to be stable may be starting to disintegrate, a conference on climate change heard yesterday. Its collapse would raise sea levels around the earth by more than 16 feet.

BAS staff are carrying out urgent measurements of the remote points in the West Antarctic Ice Sheet (WAIS) where they have found ice to be flowing into the sea at the enormous rate of 250 cubic kilometres a year, a discharge alone that is raising global sea levels by a fifth of a millimetre a year.

Professor Chris Rapley, the BAS director, told the conference at the UK Meteorological Office in Exeter, which was attended by scientists from all over the world, that their discovery had reactivated worries about the ice sheet's collapse.

Only four years ago, in the last report of the UN's Intergovernmental Panel on Climate Change (IPCC), worries that the ice sheet was disintegrating were firmly dismissed.

Professor Rapley said: "The last IPCC report characterised Antarctica as a slumbering giant in terms of climate change. I would say it is now an awakened giant. There is real concern."

He added: "The previous view was that WAIS would not collapse before the year 2100. We now have to revise that judgement. We cannot be so sanguine." Collapse of the WAIS would be a disaster, putting enormous chunks of low-lying, desperately poor countries such as Bangladesh under water - not to mention much of southern England.

Adams, Karen K NAE

From: MCha6677@aol.com

Sent: Thursday, February 24, 2005 5:08 PM

To: Energy, Wind NAE

Subject: Comment Submission on Cape Wind DEIS - Michael Charney

To: Karen Kirk-Adams
Army Corps of Engineers
wind.energy@usace.army.mil

February 24, 2005

Re: Cape Wind Environmental Review

To the Army Corps of Engineers

I submit the following statement and accompanying documents to the Army Corps of Engineers for your consideration for inclusion as additional documentation of the extremely important environmental and health benefits which will result from its approval and ultimate completion. The DEIS for Cape Wind does not, in my opinion, adequately recognize the full danger to Massachusetts and the global biosphere resulting from fossil fuel generated carbon dioxide emissions contributing to accelerated global warming, and by accompanying particulates and gases including NOx, Sox and VOCs. Several recent studies are referenced and enclosed.

The first predicts likely worsening of ground level ozone in the Northeast with expected climate warming,

Cape Wind turbines and wind farm will not contribute significantly to global warming due to fossil fuel use. Thus it would have this additional predicted benefit of not contributing to global warming nor increased stagnant pollution air episodes during summers. Its approval will help facilitate future renewable wind energy projects. Defeat of Cape Wind will subject the region to further use of fossil fuel generation and concomitant climate warming and increased regional air pollution with associated morbidity and mortality increases due to direct and indirect toxic effects of fossil fuel emissions among humans, flora and fauna. Viz:

Effects of Future Climate Change on Regional Air Pollution Episodes in the United States, Mickley et al., Geophysical Research Letters, 2004. See Boston Sunday Globe article below.

The second are two articles new scientific report estimates the toll in cardiovascular morbidity and mortality associated with particulate air pollution and finds the effects significant in loss of human life and disease causation. One must assume, until proven otherwise, that other mammals if not all mammals in Massachusetts and New England would also benefit from cleaner air through this same mechanism. Cape Wind turbines and wind farm will not contribute significantly to this local or regional air pollution or their resulting harms.

Ambient air pollution and atherosclerosis in Los Angeles, Kunzli et al, Environmental Health Perspectives, November 2004 and

Cardiovascular Mortality and Long Term Exposure to Particulate Air Pollution, Pope et al., Circulation, January, 2004.

The third article is associated with new research which has greatly heightened the concern of international climate scientists. A massive research project using donated volunteer computing power from a large array of home and desktop computers has generated a new estimate of the forcing sensitivity of the global climate in response to a doubling of carbon dioxide. The results from the ClimatePrediction.Net research, published in Nature January 5, 2005 finds that the climate system is much more sensitive to carbon dioxide forcing than previously estimated by previous researchers. The implication of this finding is that the climate system is much more sensitive to perturbation and thus the risk of an abrupt or extreme response of the climate system is ever more likely. Such a major disruption to the climate signifies much greater risk to the global and of course our regional environment. Rapid sea level rise and serious alterations in the thermohaline circulation with resulting paradoxical cooling of the Northeast US and Western Europe becomes more conceivable. Viz:

Uncertainty in predictions of the climate response to rising levels
D. A. Stainforth et al, NATURE | VOL 433 | 27 JANUARY 2005.

A fourth finding is a recent report by the British Antarctic Survey that ominous signs of melting and other destabilizing changes appear to be developing on the West Antarctic Ice Sheet, something which had not been anticipated this soon in the evolution of global warming. See accompanying article from The Independent. Viz:

West Antarctic Ice Sheet Shows Early Signs of Disintegration
Dramatic change in West Antarctic ice could produce 16ft rise in sea levels
The Independent (UK), Feb. 2, 2005

Lastly, the new head of the IPCC whose appointment had been promoted by the Bush administration has recently declared that carbon dioxide levels in the atmosphere had reached a dangerous level. Viz:

Pachauri: Climate Approaching Point of "No Return"
Global Warming Approaching Point of No Return, Warns Leading Climate Expert
The Independent (U.K.), Jan. 23, 2005

He and other prominent scientists are calling for strict and rapid reductions in carbon emissions; the ranks of scientists calling for an upper limit of 400 or 450 ppd of CO2 by the end of this century is increasing. The Cape Wind project is a necessary first step for Massachusetts, New England and the United States to promote rapid transition to clean renewable wind energy for the purpose of protecting our global environment, our biosphere's stability, our health, our economy and our future.

Yours truly,

Michael Charney, MD

3/3/2005

P.O. Box 390554
Cambridge, MA 02139
617-492-6614

[56 Kirkland St., Cambridge, MA 02138]

Enclosure & attachments.

Boston Sunday Globe, February 20, 2005, p. A-15

Warming world could worsen pollution in Northeast, Midwest
Harvard researcher to report at AAAS meeting on projected decline in cleansing summer winds

Source: Copyright 2005,
Date: February 19, 2005

CAMBRIDGE, Mass. -- While science's conventional wisdom holds that pollution feeds global warming, new research suggests that the reverse could also occur: A warming globe could stifle summer's cleansing winds over the Northeast and Midwest over the next 50 years, significantly worsening air pollution in these regions.

Loretta J. Mickley, a research associate at Harvard University's Division of Engineering and Applied Sciences, will report on these findings Saturday, Feb. 19, at the annual meeting of the American Association for the Advancement of Science in Washington, D.C. Her work is based on modeling of the impact of increasing greenhouse gas concentrations on pollution events across the United States through 2050.

Using this model, Mickley and colleagues found that the frequency of cold fronts bringing cool, clear air out of Canada during summer months declined about 20 percent. These cold fronts, Mickley said, are responsible for breaking up hot, stagnant air that builds up regularly in summer, generating high levels of ground-level ozone pollution.

"The air just cooks," Mickley says. "The pollution accumulates, accumulates, accumulates, until a cold front comes in and the winds sweep it away."

Ozone is beneficial when found high in the atmosphere because it absorbs cancer-causing ultraviolet radiation. Near the ground, however, high concentrations are considered a pollutant, irritating sensitive tissues, particularly lung tissues.

"If this model is correct, global warming would cause an increase in difficult days for those affected by ozone pollution, such as people suffering with respiratory illnesses like asthma and those doing physical labor or exercising outdoors," Mickley says.

Mickley and her colleagues used a complex computer model developed by the Goddard Institute for Space Studies in New York, with further changes devised by her team at Harvard. It takes known elements such as the sun's luminosity, the earth's topography, the distribution of the oceans, the pull of gravity and the tilt of the earth's axis, and figures in variables provided by researchers.

Mickley gradually increased levels of greenhouse gases at rates projected by the Intergovernmental Panel on Climate Change, a group charged by the United Nations to study future climate variation. Her model looked at the effect the changing climate would have on the concentrations of two pollutants: black carbon particles -- essentially soot -- and carbon monoxide, which could also indicate ozone levels. When the model first indicated that future climate change would lead to higher pollution in the Northeast and Midwest, Mickley and her colleagues were a bit surprised.

"The answer lies in one of the basic forces that drive the Earth's weather: the temperature difference between the hot equator and the cold poles," Mickley says.

Between those extremes, the atmosphere acts as a heat distribution system, moving warmth from the equator toward the poles. Over mid-latitudes, low-pressure systems and accompanying cold fronts are one way for heat to be redistributed. These systems carry warm air poleward ahead of fronts and draw down cooler air behind fronts.

In the future, that process could slow down. As the globe warms, the poles are expected to warm more quickly than the equator, decreasing the temperature difference between the poles and the equator. The atmosphere would then have less heat to redistribute and would generate fewer low-pressure systems.

With fewer cold fronts sweeping south to break up hot stagnant air over cities, the air would sit in place, gathering pollutants. Mickley's model shows the length of these pollution episodes would increase significantly, even doubling in some locations.

Mickley's collaborators include Daniel J. Jacob and B. D. Field at Harvard and D. Rind of the Goddard Institute for Space Studies.

For Additional Information:
(may become dated as article ages)

Contact: Steve Bradt
steve_bradt@harvard.edu
617-275-3628
Harvard University

Originally posted at: http://www.eurekalert.org/pub_releases/2005-02/hu-wwc021505.php
Boston Sunday Globe, February 20, 2005, p. A-15

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For Additional Information:
(may become dated as article ages)

Contact: Steve Bradt
steve_bradt@harvard.edu
617-275-3628
Harvard University

Originally posted at: http://www.eurekalert.org/pub_releases/2005-02/hu-wwc021505.php

Adams, Karen K NAE

From: Andrea Fox [afox@risd.edu]
Sent: Thursday, February 24, 2005 5:05 PM
To: Energy, Wind NAE
Subject: SUPPORT CAPE WIND PROJECT

Dear Karen Kirk-Adams,

4394

As a resident of New England, I strongly support the implementation of the Cape Wind Project. It is time to take action in establishing alternative methods of energy production and to lessen our grip on oil dependency. The Cape Wind Project will be an asset to the region.

Thank you,
Andrea Fox

Andrea Fox
Rhode Island School of Design
Department of Landscape Architecture
afox@risd.edu

Adams, Karen K NAE

From: Malcolm F Davidson [malcolm_davidson@thewisdomwheel.com]

Sent: Thursday, February 24, 2005 6:28 PM

To: Energy, Wind NAE

Subject: Wind Power Endorsement

~~004394~~

Dear Karen Kirk-Adams,

I fully support the introduction of a wind powered generator in the Cape area. We must reduce our dependance on non renewables and embrace new forms of electical energy generation.

thank you,

Malcolm F. Davidson

004395

Adams, Karen K NAE

From: Anna Sommer [info@capewind.org]
Sent: Thursday, February 24, 2005 6:16 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

004396

Dear Ms. Karen Kirk-Adams:

I wanted to take this opportunity to provide my two cents, so to speak, on the proposed Cape Wind project. Very recently we've seen in the news, a number of reports concluding that global warming is already occurring based on studies of ocean temperatures, a medium thought to be more reliable than air temperatures. In both my personal and professional life, I am devoted to policies that will mitigate or reverse the effects of climate change. I see the Cape Wind project as simply a small step in that direction. Despite the concerns of some that wildlife will be negatively impacted by the project, my concern is for the big picture. That none of that wildlife will be there if we don't start getting serious about climate change. Those who have concerns for the visual impact will have those concerns far outweighed by the benefits of the project. I see the DEIS as simply a validation of the need for Cape Wind. I support it fully and hope that you will too.

Sincerely,

Anna Sommer
168 Magazine St. #2
Cambridge, MA 02139

cc:
Capewind

Adams, Karen K NAE

From: Gale Klun [vgklun@comcast.net]
Sent: Thursday, February 24, 2005 6:18 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

004397

Dear Ms. Karen Kirk-Adams:

I don't live on the ocean but I walk the beaches as often as I can. This means that I'll be seeing the proposed towers about twice a week for many years to come. I can't wait!

If the project is successful and proves (as reports suggest) not to harm the environment, I will gaze at those turbines as do farmers at much needed rain clouds.

What's more, I belive that most voices protesting the 'distruction of the sound' will change their tune once the plant is in operation. To watch the development of this massive example of clean, safe energy is exciting and will provide a source of pride and awe to all who witness the project in action. Such an environmentally conscious endeavor is consistant with the values that make us all love the Sound. The towers will be beacons of Solutions in action.

Have a prudent plan in place and funds put away should the experiment fail or become obsolete. And then, I urge you to let this important project go forward.

Thank-you

Sincerely,

Gale Klun
428 Shootflying Hill Road
Centerville, MA 02632

cc:
Capewind

Adams, Karen K NAE

From: Tim Hagopian [thagopian@worcester.edu]
Sent: Thursday, February 24, 2005 6:31 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

It only makes sense to create power from the wind...ANY WAY and ANYWHERE WE CAN. We cannot continue our huge consumption of energy AND refuse to make the energy in a responsible way. PLEASE support the Cape Wind project.

004398

Sincerely,

Tim Hagopian
486 Chandler St
Worcester, MA 01602

cc:
Capewind

Adams, Karen K NAE

From: K.D. Gifford [gifford@oldwayspt.org]

Sent: Thursday, February 24, 2005 6:25 PM

To: Energy, Wind NAE; mepa@state.ma.us

Subject: Cape Wind DEIS/DEIR

February 24, 2005
TO: US Army Corps of Engineers
TO: Mass Executive Office of Environmental Affairs

Karen Kirk-Adams
Cape Wind Energy EIS Project
U.S. Army Corps of Engineers
New England District
696 Virginia Road
Concord, MA 01742 wind.energy@usace.army.mil

004399

Secretary Ellen Roy Herzfelder
Executive Office of Environmental Affairs
Environmental Policy Act Office
Attn: Anne Canaday
100 Cambridge Street, Suite 900
Boston, MA 02114 mepa@state.ma.us

Re:
US Draft Environmental Impact Statement (DEIS)
MASS. Draft Environmental Impact Report (DEIR)
Cape Wind Project, Nantucket Sound

February 24, 2005

FROM:
K. Dun Gifford
5 Hinckley Lane, Nantucket, MA 02554 gifford@oldwwayspt.org
RE: Draft Environmental Impact Statements, Cape Wind Project, Nantucket Sound

Dear Ms. Kirk-Adams and Ms. Canaday,
I am submitting these comments to urge that your agencies approve the Draft Environmental Impact Statement (DEIS) and the Draft Environmental Impact Report (DEIR) for the Cape Wind project, which analyzes the proposed construction and operation of a wind farm on Horseshoe Shoal in Nantucket Sound, off the southeastern coast of Massachusetts.
I am a property owner on Nantucket, and am very familiar with Nantucket Sound and Horseshoe Shoal. Since I was a small child I have traveled back and forth across the Sound, in boats and on planes.
My earliest crossings of Sound were aboard Steamship Authority vessels in the 1940s, during World War II. In those days the vessels departed for the Islands from New Bedford, and had to navigate the tricky waters and tidal currents of Woods Hole Harbor to get to Nantucket Sound. My large extended family and I still travel across the Sound regularly on both Authority vessels and Hi-Line vessels.

We also fly to and from Nantucket regularly.
My support for the Cape Wind project is based on these aspects of the project.
Threat to Navigation. For nearly 50 years I have skippered sail and power boats across and around Nantucket Sound, on clear days and in pea soup fog; circumnavigated both Nantucket and Martha's Vineyard numerous times, and been in and out through Muskeget Channel and also the various channels between Great Point and Monomoy Point. In all of this time I have never seen a singe boat aground on Horseshoe Shoal. As a experienced sailor, I am mindful of the risks to navigation that the Cape Wind project poses to people who are inexperienced boaters. I am also mindful that wind farms like this Cape Wind project are currently operating in waters all over the world. I have a hard time accepting the premise that Americans would crash their boats into the wind farm towers in Nantucket Sound, while peoples of other nations in the world are not crashing their boats into their wind farm towers.
Technology. I am also a former Chairman of the Board of the Nantucket Electric Company. It was during my tenure as Chairman that an experimental wind farm was constructed in the southwest of the island on the Bartlett Farm near Cisco Beach, and connected to the Nantucket Electric Company system.
These wind generators supplied power to the system for a few years, but were removed after recurring damage from wind-borne salt spray and wind-blown sand. In the 1980s, wind-generation technology had not advanced sufficiently for construction and operation of long-life wind generating turbines in this kind of salt-and sand regimen.
Fortunately, time marched on, technology advanced, and long-lived wind generators are now deployed in many parts of the world in weather conditions more severe than Nantucket Sound's.
Air Pollution. The evidence is clear that *any reduction in fossil fuel emissions from generating plants burning fossil fuel* is an immediate health benefit. The reason is that the air will be cleaner the minute that the Cape Wind project begins to generate power, because it will reduce the amount of coal and oil that would otherwise be burned to generate that power. This benefit accrues not only to individuals who live or work downwind of such a plant or plants and within its exhaust footprint, but also for individuals who travel through, or vacation within, its exhaust footprint.
Water Quality. The evidence is also clear that *any reduction in fossil fuel emissions from generating plants burning fossil fuel* will improve water quality in the area of Nantucket Sound, Vineyard Sound and Cape Cod Bay. This is true for the fresh ground water which supplies drinking water for communities in the area, because gravity draws the noxious elements in the smokestack exhausts of the Brayton Point Power Plant and the Cape Cod Canal Power Plant to the ground, where they then percolate down into the ground water. These noxious elements also fall onto fresh water ponds, and can end up in the drinking water this way, too.
They also fall into the salt water sounds, bays, harbor, estuaries, tidal marshes and the ocean itself. Some of the noxious exhaust elements are dissolved in the water, while some are not and fall to the bottom. They include such harmful substances as mercury. The noxious elements include carbon dioxide, sulfur dioxide, nitrogen oxide, particulate matter, carbon monoxide, and volatile organic compounds. When the Horseshoe Shoal wind farm begins to generate power, it will reduce the amount of these noxious air pollutants by an astounding amount. Using the data reported in the DEIS, it will reduce current sulfur dioxide emissions by *more than 4,600 tons each year*. It's hard to imagine 4,600 tons of a gas like sulfur dioxide would it fill A billion billion ballons? 100 cubic miles? Mt. Washington? Whatever the measure, it's certainly got to be a big number.
Even better for health, the Horseshoe Shoal wind farm will reduce "particulate matter" by 177 tons each year. Particulate matter is the ash, soot, and dust in the smoke that is produced when coal and oil are burned, and it contains the chemicals that make people

cough and their eyes run when they are enveloped by the smoke.
It's also hard to imagine how large a mountain of ash, soot, and dust that 177 tons of very small bits of particulates will build, but it's surely not a small one.
Five generations of my family have fished and shellfished in and around Nantucket, and each generation has caught smaller and fewer fish and shellfish than the generations before it. There is increasing evidence that noxious chemicals in the emissions from fossil fuel power plants particularly those from the great coal-and-oil fired power plants of the American upper mid west are interfering with fish and shellfish reproductive systems in the lake and salt waters of the northeast.
We know these emissions as haze, smog, or ozone, and are regularly warned about them when levels rise dangerously in the summer months. The Cape Wind project will be a major beginning towards reducing power plant emissions in the northeast. This may mean that our grandchildren and great-grandchildren will know the wonderful fishing and shellfishing that our parents and grandparents knew.
Visual Issues. "Beauty," as the saying goes, " is in the eye of the beholder."
I have never come across writings that describe the Cape Cod Canal power plant and the Brayton Point Power Plant, or the brown haze that pours night and day from their smokestacks, as beautiful. But there are bookshelves full of writings that describe them as grim and ugly.
Almost everyone, resident or tourist, believes that the small, shingled windmills dotting hilltops around the Cape and Islands are postcard-beautiful. Most environmentalists and conservationists think that modern wind-powered electricity generators are beautiful, too, because they understand how insidious the exhaust from fossil fuel power plants is for living things.
There is, however, an exception to this general rule. Some otherwise dedicated environmentalists and conservationists are convinced that if they can see modern wind-powered electric generators from their homes, they will be ugly. For these individuals, apparently, the only good wind-powered generators are those below their horizon line; "out of sight, out of mind." To be sure, this opinion is usually honestly held and to be respected. The question, though, is whether it's the soundest opinion.
In sum. A close reading of the DEIS makes clear that the environmental benefits of the Cape Wind project are many, and very broad. It also makes clear that it has equally positive health benefits for virtually everyone soldier, sailor, tinker, spy; tennis players, golfers and fishermen; and old and young. This is true for those within sight of the wind farm or a hundred miles away.
When all is said and done, if the choice were between great health and great views, most of us would rather have the good health. And that's exactly the choice here, as the DEIS data makes evident.
Thank you very much for your attention to this comment, and again, I urge you to approve the DEIS and the DEIR for the Cape Wind project.
Very truly yours,

K. Dun Gifford
5 Hinckley lane
Nantucket MA 02554
gifford@oldwayspt.org

Adams, Karen K NAE

From: Gerry Dameron [gerry@patriotwind.com]

Sent: Thursday, February 24, 2005 6:12 PM

To: Energy, Wind NAE

Subject: Support for America's first offshore wind installation

0044100

Dear Army Corps of Engineers,

Please note the support of myself, and thousands of other Americans who adamantly and passionately support the implementation of America's first off shore wind facility, Cape Wind, off the coast of Nantucket, where the turbines will look like tiny toothpicks on the horizon, if at all.

Debates have been raging for several years now, not based on real and compelling issues, but mostly because of corporate media types who specialize in supporting the status quo for energy generation in the U.S. The power elite in power marketing, like those executives at Enron, are hell bent on maximizing obscene profit levels while they can still build their overflowing retirement war chests. The media never complained about unsightly oil derricks, easily visible on the shoreline of California – why are they complaining vociferously about little ¼ inch dots on the horizon, now that it is wind power and not oil power?

All this while we continue to burn more coal -- allowing mercury levels to continue to rise, respiratory ailments and asthma are at an all time high, early childhood respiratory diseases are increasing, and acid rain has killed half the lakes in the Midwest and Ohio river valley. More natural gas (nothing "natural" about it) combustion is anticipated, even as prices for a dwindling supply of gas triple in a year, while countless gas combustion electrical generation facilities are lying fallow from bankruptcy after the tripling of costs. All this while scientifically substantiated concerns over potentially catastrophic consequences from rapid climate change are discussed behind closed doors by DOD top dogs, generals and government officials. The National Geological Survey states that in spite of record droughts throughout the U.S. we continue to use 39% of all our fresh water every year to cool fossil fuel power plants in the U.S. No one of any intellect expects that these policies can endure.

And we still see the American media playing it's fiddle for incumbent energy concerns and infrastructure. Have we ever seen so many lazy and complicit journalists fiddling together in a cacophony to be likened to 5 symphony orchestras of overpaid musicians on LSD playing expensive instruments at top volume – blasting blatant inflammatory misinformation to confuse and paralyze public opinion while Rome (all of the U.S.A.???) is about to burst into hell-like flames? Costs for generating electricity, at 1 cent to 2 cents 30 years ago, are already at 10 cents and 13 cents a kWh in many parts of the U.S., and they are headed to 19 cents in a very few years – representing an increase of 500% to 1000% in very few years. And what will prices be when oil is down to 20% of 1960 production levels, at $80 a barrel, and we are importing 80% of our oil from one of the 5 remaining countries with oil? But misinformation in the American media is now a clichė, and the Europeans are gleefully ready to eat our lunch for the next 50 to 100 years based on our inability to react in a new way. Why wake us up? Let us sleep until our energy infrastructure reduces us to financial ruin for all but the top 2% of the American population who are insulating themselves with oil cash currently being generated in Iraq at a staggering, yet unsustainable, level.

The trumped-up "battle" over Cape Wind has been an embarrassment for those of us knowledgeable of and involved in renewable energy endeavors. Off shore has been an established, cost-effective, growing, and proven industry overseas, exemplified by numerous projects in Europe, including the often-photographed Horns Reef project off the shores of Denmark.

Can we get out of our own ways and learn something from countries that are leading the way, and who are securing for themselves a future of competitive and sustainable energy and economic infrastructure, all while improving -- rather than decimating -- the natural environment that we all need and rely on to survive as a species. Wind Power is proven. New wind power is already at $25 Billion in world wide infrastructure, is cheaper than nuclear, hydro, geothermal, and (natural) gas for setting up and running new electricity plants. Wind power uses no fuel, and thus has not fuel cost escalation risk associated with it, and it uses no water. Wind power can be deployed in 15% to 25% of the land mass of the U.S. according to DOE reports, allowing us to power 505 or more of the U.S. in just a couple of decades. Let's stop misinforming the public and creating shadow boxing matches in the media. Let's put wind power – the new technological and economic workhorse - to work before its too late and Europe, China, and the rest of the world have us outwitted and overpowered for the next two hundred years.

best wishes,

Gerry Dameron
President
Patriot Wind

Wind Power for Municipalities

Visit our New Web Site at: www.PatriotWind.com

gerry@PatriotWind.com

Office Phone: (303) 444 - 1122
Mobile Phone: (303) 503 - 1122
Fax: (303) 444 - 3699

Adams, Karen K NAE

From: Marcell Graeff [m.graeff@dinisco.com]
Sent: Thursday, February 24, 2005 5:09 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

004401

My name is Marcell Graeff. I live in Cambridge and work as an architectural designer in Boston in the high performance, "green" and sustainable public schools field. As a designer, I am a member of the Boston Society of Architects (BSA), the Northeast Sustainable Energy Association (NESEA), and the United States Green Building Council (USGBC) through which I am a Leadership in Energy & Environmental Design (LEED) Accredited Professional. As a private citizen I am a member of the Sierra Club and contribute to the Natural Resources Defense Council (NRDC).

Recreationally, I am an avid windsurfer and sailor of small boats, and I have witnessed first-hand the power of Cape Cod's winds. There is no other place on the Northeast coast that I love as much as the beaches, coastal wetlands, and bays of Cape Cod. And there is no place I'd rather be sailing in than that backdrop of the Cape's interface between land and water, between humankind and nature, and the delicate balance of the inter-relationship between the two. Realizing that, I am a strong supporter of Cape Wind's proposed energy project in Nantucket Sound which could supply 70% of the Cape & Islands with clean and renewable power.

This is the right time and Cape Cod is the right place for America's 1st offshore wind farm precisely because it is such a fragile place whose environment and inhabitants cannot further afford the negative impacts on the air and water quality of the region by burning coal and oil for power generation. It is wrong for us to ignore any longer the significant wind resources for utility scale power generation that are found off the Cape's shores. I believe we have the power to choose how we envision the Cape Wind project. Some people choose to see the wind turbines as beautiful. Others choose to see them as a blight on the landscape. And some could care less as long as they remain out of their sight. With all the significant benefits wind power has to offer society (the reduction of global warming, cleaner air to breath, cleaner water to navigate and fish from, reduce America's dependency on foreign oil, and more), it's a shame we can't build upon this very necessary change toward sustainability with clean, renewable energy. The Cape Wind energy project presents a unique opportunity to connect the Cape Cod community to its energy source and to make renewable energy visible and meaningful to its users.

As a designer, I challenge the developer, Cape Wind Associates and the regulating authority, the Army Corps of Engineers, to step back and think of the impact this precedent setting wind farm could have on the Cape and Island's and the nation's perception of wind power. I would like Cape Wind to plan for a specific program of public outreach and education once the wind farm utility is built. The public should be able to easily understand the output of the wind farm's renewable energy, its environmental impacts, health & economic benefits, etc through interpretive exhibits installed at visitor center(s) on the Cape & Islands. The public should actually be able to visit the wind farm in Nantucket Sound. In conjunction, I would also like Cape Wind and the Army Corps to anticipate secondary uses of the wind farm area on Horseshoe Shoal.

Why can't a wind farm be a park, a research center, a tourist destination, a place for families to bring their children to learn about the environment and renewable energy? Instead of trying to hide the wind park, how can we make the meaning behind the infrastructure visible to those who can't see?

In trying to address both sides of the Cape Wind energy project debate, a group of concerned architects, including myself as the co-chair, have organized a national ideas design competition - WINDSCAPE, with sponsorship from Boston Society of Architects (BSA), to be held from May to December of 2005 to provide architects and other designers a broad forum for dialogue and to explore ideas and produce new and exciting creative visions about this project that may not have yet surfaced. The WINDSCAPE design competition challenges entrants to envision a Cape Wind Park that is more than just a utility to generate electricity, but a place to educate the public about the impacts of renewable wind energy on the environment. For more information, please visit www.architects.org/windscape.

Thank you,

Marcell Graeff
59 Henry St. #2
Cambridge, MA 02139

Sincerely,

Marcell Graeff
59 Henry Street
Unit #2
Cambridge, MA 02139

cc:
Capewind

Adams, Karen K NAE

From: Peter Brooks [pbrooks@donhamandsweeney.com]
Sent: Thursday, February 24, 2005 5:24 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

Dear Ms. Karen Kirk-Adams:

004402

I am urging you to please support the Cape Wind proposal to construct a wind farm in Nantucket Sound. I am a registered Architect in the Commonwealth and have followed this controversy closly. I am also a an Acredited Profesional of the Leadership in Energy and Environmental Design program of the US Green Building Council. I understand the there has been studies of the impact on birds, fish, wildlife by the US Army Corps of engineers and that they support the proposal because they have found that it wil not cause significant problems. They have found that it is not a hazard to shipping or commerce. Some people who live on the the edge of the water beleive that there pleasant view will be compromised by the site of many elegant machines far out at sea. Speaking as an environmentalist and a practical old Yankee from the south shore I support this project. I will not support any politicians opposed to the plan even if they are Kennedies. I can not believe that any one would oppose a project which will provide most of the power for the Cape in a sustainable manner, with out the need for foreign fossil fuels. It is beyond the time when we should be weaning our nation from the dependancy on foreign fossil fuels. This project is a major step in the right direction for our state , which so far seems to have been resistant to the need to move into the new energy millenium. The project is only being held up by those who are afraid of change because they do not understand that the new energy future is inevitable. Lets move into the future as gracefully as we can; without more wars over fossil fuels. Please support this project, you wil not regret it.
Thank you for your consideration.
Peter Brooks

Sincerely,

Peter Brooks
68 Pearl Street
Watertown, MA 02472

cc:
Capewind

Adams, Karen K NAE

From: Gail Trachtenberg [g.trachtenberg@lozano-baskin.com]
Sent: Thursday, February 24, 2005 5:24 PM
To: Energy, Wind NAE

Dear Karen Kirk-Adams,

004403

I strongly support the Cape Wind project because, as indicated in the report, the installed project will clean the air enough so that the people of New England will save $53,000,000 from less disease. The health benefits alone are a strong reason, but this issue also addresses the significance of the cost savings, which lead to economic strength. Also supporting economic strength resulting from the Cape Wind Project are the lower electric rates for New England on the whole.

Gail P. Trachtenberg, R.A.
Lozano, Baskin, and Associates, Inc.
6 Bennett Street
Cambridge, MA 02138
(t) 617 868-6344 x 106
(f) 617 661-9228

Adams, Karen K NAE

From: Andrew Bowersox [a.sox@comcast.net]
Sent: Thursday, February 24, 2005 5:34 PM
To: Energy, Wind NAE
Subject: wind park project on Horseshoe Shoal

004404

Dear Ms. Karen Kirk-Adams:

As far as I can determine, there is no benign means of producing 400MW of electrical power. But Americans do love their energy, so we will certainly need that power.

Before continuing to make a broad case is support of the Cape Wind proposal, let me first make two specific suggestions related to the EIS. First, with the price of energy having risen recently, I would like to suggest that you revise the economic analysis of the EIS to reflect the current and projected cost of energy. Second, I would like to see a model developed to analyse the economic benefits of selling the electrical power locally through the Cape Light Compact, rather than spread out across the New England grid.

When considering the costs and benefits of the Cape Wind proposal, we need to ask ourselves the question, "compared to what?" In New England, we get our electriciy from coal, oil (25% in NE, the percentage being substantially higher in SE Massachusetts), natural gas, hydroelectric, and nuclear power. Against these alternatives, wind power at the utility scale is benign.

In light of the ecological impacts associated with the extraction, distribution, and combustion of fossil fuels, industrial scale wind power is benign.

Global warming theory is debatable only among politicians and media pundits. Among the scientific community, global warming theory enjoys the same degree of consensus as evolution, and reletivity. The abundance of scientific evidence begs us urgently to take action. The Cape Wind proposal is a means of doing just that.

Let us not forget the health impacts of air, water, and soil pollution caused by the combustion byproducts of fossil fuels.

Let us not forget the decimated salmon stocks caused by hydroelectric power.

Let us not forget Chernoble, or Three Mile Island, or the exhorbitant cost and unimaginable duration of time associated with the storage of nuclear waste. By comparison, utility scale wind power is benign.

I'm willing to avow that there will be costs, and sacrifices associated with the Cape Wind project, but lets us never forget to ask ourselves, "compared to what?"

Sincerely,

Andrew Bowersox
41 Edgewater Rd.
Mashpee, MA 02649

cc:
Capewind

Adams, Karen K NAE

From: Katie Barrett [k8ie_@hotmail.com]

Sent: Thursday, February 24, 2005 5:00 PM

To: Energy, Wind NAE

Subject: Testimony FOR Cape Wind

004405

Re: Karen Kirk-Adams
Cape Wind Energy EIS Project
U.S. Army Corps of Engineers
New England District
696 Virginia Road, Concord, MA 01742

Dear Karen Kirk-Adams,

I am in favor of the Cape Wind project because of its apparent health benefits and because of the vast amounts of money that the state and Cape region will save in the long run. Also, I feel that aethetically, they would be a beautiful sight to see. I do not see or agree with any reasons that people may have against the wind farm.

Thanks.

Katie Barrett of Bourne, MA

Adams, Karen K NAE

From: John E. Johnnidis [jejlex@rcn.com]

Sent: Thursday, February 24, 2005 5:03 PM

To: Energy, Wind NAE

Subject: Cape Wind Project

On both aesthetic and practical grounds, I strongly support the Cape Wind project. This country must reduce its dependency on fossil fuels and the sooner an intelligent transition to renewable sources of energy begins, the better off our economy and society will be. If the only reason the dissenters can cite is that their view will be spoiled, then society should not be held hostage to a minority group's standard of beauty- a vista of graceful machines, drawing on the natural wind currents that our planet supplies, can be attractive in its own right.

004406

Adams, Karen K NAE

From: stormpetrel@gis.net
Sent: Thursday, February 24, 2005 5:01 PM
To: Energy, Wind NAE
Subject: Comments on Cape Wind energy project

004407

Dear USArmy Corps of Engineers: Please consider my comments about the Cape Wind project.
As one speaker said "All thinking people support renewable energy". I support wind energy.
However, I also strongly support conservation, and believe that Americans could do a lot
to cut down on electricity use.
Having said that, I have concerns about the DEIS, both from my own reading, and from comments made by people with more expertise that I at the hearings. Specific environmental and ecological issues, particularly concerning birds, marine mammals, fish, noise, light pollution, shifting sedimentation and other issues, were not sufficiently addressed in the DEIS. At the least, a supplemental report should be filed. Even more important, the issues of private development of a public resource, and the lack of clear guidelines and standards are nowhere addressed in the report. I understand that legally the ACE may not have to address these issues. However, I also understand that the ACE's authority derives from a statute that is over 100 years old!
I am dismayed that no consideration was given to alternative sites, or a smaller scale
project. Given the huge outcry of protest from local and state governmental officials,
chambers of commerce, and various interest groups, as well as non-affiliated citizens,
it would be prudent to proceed with only the utmost caution. Unfortunately, a lot of
people already think that the ACE doesn't ever see a big construction project
that it doesn't like, and the tone and results of the DEIS so far seem to confirm that
belief.
In summary, I urge the ACE to undertake a major revision of the DEIS, addressing all
the areas which were inadequately addressed in the first place, and even to consider
a recommendation that the project NOT move forward until the concerns about use of
Nantucket Sound by a private entity, and the REAL public interest, are addressed.
Thank you for your attention. Sincerely, Suzanne Phillips, Box 321, East Orleans, Mass.

Adams, Karen K NAE

From: Amy Hutchins [ahutch55@gmail.com]
Sent: Thursday, February 24, 2005 5:01 PM
To: Energy, Wind NAE
Subject: In favor of Cape Wind

Dear Karen Kirk-Adams,
I am in FAVOR of the Cape Wind Project because, not only is it a great energy source, but it is also a healthy way to get energy.
Thank You!
Amy Hutchins
RWU Architecture Student

004408

Adams, Karen K NAE

From: Gabriel Shapiro [gcshapiro@hotmail.com]
Sent: Thursday, February 24, 2005 5:05 PM
To: Energy, Wind NAE
Subject: Cape Wind Project

Dear Ms. Kirk-Adams,

It was a pleasure to meet you at the Cambridge public hearing In December. I would like to follow up my comments there with a written submission. I am strongly in favor of the wind farm project and I think the Army Corps has done a great job so far. Here are my suggestions

004409

Avian Effects:
I think the Corps has to be clearer that they used the most conservative estimates to calculate bird deaths. The often quoted statistic of a bird death per day represents the MAXIMUM number of bird deaths possible according to the methodology, but is often stated as an average. I think that this is an important distinction to make as the it is likely that the bird deaths will be far fewer that one per day.

Visual Effects:
Since the windmills will only be visible on very clear days, I think the Corps should include a study of how many days during the year the project will be visible from various points. I think you will find that the windmills will be visible less often that people realize.

Oil Storage:
Please, please clear up the ridiculous rumors being spread about the non-toxic mineral oil that will be used in the mills and the transformer. The degree to which it is far less dangerous and toxic than crude oil must be quantified and clearly stated in the final impact statement. The near impossibility of a major spill of this fluid should also be quantified and included.

In general, I hope this process of public comment ensures that the Corps will address the false assertions and fear mongering by the opposition. The Corps should go out of its way to debunk criticism of the impact statement however ridiculous the attacks may seem. Thanks for all of your hard work on this and for letting me add my two cents twice.

Sincerely,

Gabe Shapiro
Co-Director, Clean Power Now, Boston Chapter

Adams, Karen K NAE

From: Ggwattley@aol.com
Sent: Thursday, February 24, 2005 5:33 PM
To: Energy, Wind NAE
Cc: anne.canaday@state.ma.us; pdascombe@capecodcommission.org
Subject: Comment on Cape Wind DEIS: Missing SIS, NEPOOL and Project Costs

004410

Ms. Kirk-Adams:

Attached is a letter that addresses the above three topics concerning the Cape Wind DEIS.

Unfortunately, the four enclosures for the letter are large reports/files and must be send separately.

I apologize for the inconvenience.

Thank you for your consideration.

Glenn Wattley

41 Winchester Street
Boston, MA 02116-5305

February 24, 2005

Ms. Karen Kirk-Adams
Manager, Cape Wind Energy Project EIS
U.S. Army Corps of Engineers
New England District
Regulatory Division
696 Virginia Road
Concord, Massachusetts 01742

Transmitted via e-mail: wind.energy@usace.army.mil

RE: Comments on DEIS for Cape Wind Project

Dear Ms. Kirk-Adams:

I appreciate the opportunity to submit a written statement to the Army Corps of Engineers (ACOE) concerning the Cape Wind Associates, LLC (Cape Wind) Draft Environmental Impact Study (DEIS) for the proposed wind-farm power plant. I have worked in the energy industry almost 30 years, and I support the development of renewable energy resources. I have experience performing "due-diligence" work on technical and economic matters for dozens of energy projects throughout the world, including renewable energy.

On December 16, 2004, I attended the ACOE DEIS public hearing held at MIT in Cambridge and read my statement to the ACOE stenographer who was outside the hearing room. I provided the stenographer with a copy of my statement. While the DEIS is an impressive document reflecting thousands of hours of work, there are several required reports/analyses missing. This letter will expand upon my December 16th statement. It will address three topics, which speak to the incompleteness and inaccuracy of the DEIS findings. The missing analyses address important technical, environmental and economic impacts. These should be included in the DEIS, or a Supplemental DEIS as recommended by the Cape Cod Commission (CCC). These are:

1. **The System Impact Study (SIS)**, which Cape Wind and NSTAR are required to develop and gain approval from the Independent System Operator of New England (ISO NE), the NEPOOL High-Voltage Transmission Grid Operator;
2. **The Analysis of Additional Operational Costs Incurred by ISO NE/NEPOOL** if the wind-farm power plant were to be integrated (there will be "material" grid operational costs incurred if Cape Wind were to produce power, and these costs will offset benefits Cape Wind claims the power plant will create in the ISO NE wholesale energy market); and

3.**T he Project or Power Plant Economics**, that is, the "total cost of electricity" produced from the power plant, which despite large public subsidies (millions of federal and state dollars), the Cape Wind project will not be economically viable and thus the long-term benefits (environmental and economic) shown in the DEIS will not be realized.

I will address these topics in the order presented above. I note that these are interrelated. For example, the missing SIS will contain technical and economic analysis/findings that will impact the other two.

Topic 1: The Missing ISO NE/NEPOOL SIS

Setting the Context: As I stated at the MIT hearing, ISO NE requires and must approve an SIS for new generators/power plants.[1] The SIS identifies the technical and economic impacts to the NEPOOL Grid that arise from "integrating" or connecting the new generator. Integration is a complex process to ensure safe and reliable high-voltage transmission of energy from the new power plant.

To further illustrate the importance and complexity of wind-farm integration, I provide for the ACOE review, The New York State Energy Research and Development Authority (NYSERDA) recently commissioned a "system integration study" entitled: ***The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations***. As you will see, GE Energy's consulting group conducted the study for NYSERDA. GE Energy is a major vendor/supplier of wind energy turbines. Cape Wind has selected the GE 3.6 MW offshore generator for the Cape Wind power plant.

This NYSERDA-GE study presents several technical reasons why wind-farm integration into a transmission grid is a complex matter. The study explains why wind power plants are "not reliable" sources of power when compared with other sources of power. While the DEIS mentions the fact that wind generators are "intermittent resources," there is no analysis within the DEIS addressing how ISO NE/NEPOOL will integrate Cape Wind's power plant to ensure grid security and reliability. The NYSERDA-GE report has many recommendations for new rules, upgrades and new operational procedures. These GE findings/recommendations have costs associated with them, and are relevant to the Cape Wind project. These costs should be addressed in the DEIS, or a Supplemental DEIS.

Also, it is important for the ACOE to recognize that the Federal Energy Regulatory Commission (FERC) is in the process of holding hearings that will result in promulgation of new rules for wind farm integration. FERC has initiated its process of Notice of Public Review (NOPR)[2]. FERC recognizes the complexity of integrating intermittent resources

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[1] ISO NE Paper: What is a System Impact Study and Why is it Necessary...to...Interconnect New Generation? (ISO NE web site) Also, as a point of interest, the ISO NE web site showed at one time that Cape Wind applied to ISO NE for an SIS in June 2001. The EFSB applicants have known the importance of the SIS for well over three years.

[2] FERC NOPR: Docket No. RM05-4-000, dated January 25, 2005

such as wind farms. The FERC NOPR is concerned factors such as low voltage pass through, SCADA updates, and power factor range requirement. The point being that the DEIS is void of such important discussions, analysis and findings on how Cape Wind will address these issues, and the cost for FERC compliance.

The SIS and The EFSB: As discussed in the DEIS Section 7.3.2.1 Cape Wind and NSTAR applied to the Massachusetts Electric Facility Siting Board (EFSB) for a permit to install two (2) underwater 115 KV transmission lines to connect the wind farm power plant to the Barnstable Switching Station, which is the point of interconnection to NEPOOL. NSTAR represented at the initial ESFB public hearing that the SIS is required and would be prepared and released for EFSB and public review, and for ISO NE approval. I enclose a copy of the NSTAR presentation dated October 31, 2002. According to Mr. Charlie Salamone of NSTAR (please refer to page 9 of the presentation), the SIS was to be completed, submitted and approved by ISO NE (and a host of other stakeholders) within or about one year.

Also, during the EFSB discovery process, Cape Wind's response to an EFSB interrogatory[3] informed the EFSB that the "preliminary" results of the SIS would be available in three months, which would have been in April 2003. Mr. Salamone, who authored the response, indicated NEPOOL had approved the scope of work for the SIS, and the final SIS was to be completed by October 2003. Therefore, the SIS should have been available well over a year ago. To my knowledge the SIS has not been released for review and certainly has not been approved by ISO NE.

I note that Mr. Salamone's public presentation confirmed the importance of the role of the SIS to the project development and approval process. He pointed out that the SIS would identify the upgrades needed to the NEPOOL Grid _beyond the Barnstable Switching Station_. All such upgrades will be on Cape Cod and Massachusetts land, which is of interest to the Massachusetts Environmental Policy Act Office (MEPA) and the CCC. During the CCC February 8, 2005 DEIS hearing, Cape Wind made the point that the CCC should not address issues "outside the CCC's jurisdiction." The upgrades to NEPOOL on Cape Cod beyond the Barnstable Switching Station are certainly within the CCC and MEPA jurisdiction.

Transmission Constraints in the Region: It is well known that the NEPOOL Grid in Southeastern Massachusetts (the SEMA region) has transmission congestion.[4] Mr. Salamone indicated this fact (NEPOOL transmission map on page 5 of NSTAR presentation). With a generator the size of the proposed Cape Wind power plant, future efficient and reliable power flows in this region might require an additional 345 KV transmission line from mid-Cape across the Canal.

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[3]Mr. Charlie Salamone, of NSTAR authored the Cape Wind Response to Interrogatory ESFB-15. Mr. Salamone's response was consistent with the public representations made when in the NSTAR power point presentation concerning the timing of the release of the SIS.

[4] ISO NE Study: Congestion Management System (CMS), Implementation Studies Related to Congestion, dated January 14, 2003.

I make note of the fact that the importance of transmission congestion is discussed in the DEIS Section 3.0 Alternative Analysis, where there are analyses of many alternative projects. In Section 3.0, at least six (6) references (pages 14, 24, 30, 31, 32, 36) are made to Appendix 3-D, which discusses a possible 345 KV transmission line for the New Hampshire-Maine region. The DEIS analysis concludes that this NH-Maine region is not suitable for alternative projects because a 345 KV line would have to be constructed.

It is "ironic" or "inconsistent analysis" that the importance of transmission constraints is addressed for some of the alternative projects, but there is no similar analysis for the Cape Wind project. In fact, congestion in SEMA is equal to or greater than that found in the NH-Maine region[5]. One would think this topic is highly relevant and critical for the Cape Wind project.

Transmission constraints for SEMA should be presented in the DEIS. This is an excellent reason why the SIS needs to be in the DEIS, or a Supplemental DEIS. If an additional 345 KV transmission line is needed (or not needed) in SEMA, the DEIS requires such a statement, with supporting analysis. This is a significant component of the project. The ACOE, MEPA, CCC and the public at large should have the opportunity to review and to understand the total impacts – environmental and economic – on NEPOOL.

One final point on the matter of 345 KV transmission lines: I draw your attention to a statement within DEIS Appendix 3-D, page 6 which states, "Any realistic analysis of a potential land-based 345 KV line expansion project must recognize the political opposition that would likely arise." I agree the construction of transmission lines raises many difficult hurdles including political and local resistance. This is true for the Alternative Analysis and for the Cape Wind project. The missing SIS has delayed public disclosure that the Cape Wind project will require expensive NEPOOL upgrades, such as a 345 KV line expansion in SEMA. Certainly the MEPA, the CCC, the EFSB and public have a right to know the findings of the SIS prior to any permit approvals, because the costs can be large.

For example, in the Boston area, an 18-mile 345 KV transmission line was approved recently for construction. Depending upon which news source one reads, the cost of this expansion will be $177 to $210 million.[6] This means the capital cost for this 345 KV line is approximately $10 million per mile. The cost of construction a 345 KV transmission line in SEMA would most likely cost less. I respectfully point out that the burden is on

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[5] ISO NE Study: Christensen has performed congestion studies for ISO NE, and the reports show that SEMA is an area of congestion similar to the NH-Maine region. By identifying NH-Maine as a region of congestion that would require a 345 KV transmission expansion, Cape Wind reveals that it is well aware that transmission congestion on the NEPOOL system is an important topic of analysis and investigation. The ISO NE studies show is an issue for power flows in SEMA.

[6] *Platts T&D* dated February 1, 2005 identifies the 345 KV line for the Boston area as being 17.5 miles long and costing $177 million. The Epsilon Associates web site show the line as being 18 miles long and costing $210 million.

Cape Wind and NSTAR to disclose such costs. The SIS could show that such an upgrade will exceed $30 to $50 million.[7] This will add considerable cost to the project, and this cost would be the responsibility of Cape Wind Associates, LLC. These costs will further impact the potential viability of the project (topic 3 of this letter). As the DEIS concludes, additional transmission line construction prohibits alternative projects, the same is probably true for Cape Wind, and must be examined.

Release the SIS for the Supplemental DEIS: I support the CCC recommendation that the ACOE produce a supplemental DEIS. A supplemental DEIS would afford Cape Wind the opportunity to incorporate the SIS. This will assure the public that indeed the many technical integration issues being raised by the FERC NPOR and NYSERDA-GE study will be satisfied in the case of Cape Wind's project.

Topic 2: Missing Cost Analysis for ISO NE – NEPOOL Operation

Setting the Context: Related to the missing SIS is the fact that the DEIS is void of important technical and cost analyses concerning the operation of ISO NE and the NEPOOL Grid if the Cape Wind power plant were to be integrated. As indicated by Mr. Salamone of NSTAR (page 10 of NSTAR October 31, 2002 presentation), there are operational or areas of "concerns" such as dynamic response and protection system coordination. The NYSERDA-GE report discusses similar problems; the FERC NOPR is addressing several as well; these operational problems must be addressed for efficient, safe and reliable NEPOOL operation. The DEIS is void of analyses of how Cape Wind will resolve these technical issues, and the DEIS is missing the additional costs ISO NE and NEPOOL will incur if the wind-farm power plant were to operate.

The LaCapra Study Does Not Address Related Costs: The DEIS contains a study by LaCapra Associates (Appendix 5.16-B), which addresses many issues including the Cape Wind power plant's commercial activity of selling energy/power into the ISO NE wholesale market. This LaCapra study is presented as a definitive analysis of ISO NE market benefits, which are claimed to be $25 million of annual savings.

However, there are two reasons the LaCapra report, which is dated January 10, 2003 is not credible for the DEIS: 1) the LaCapra study is "biased" or incomplete in that it addresses strictly claimed benefits and totally ignores associated NEPOOL costs; 2) as of March 1, 2003, less than two months after its release, the LaCapra analysis is obsolete because the ISO NE adopted Standard Market Design (SMD) rules. The LaCapra report is "silent" on SMD and unfortunately addresses only the "old" market dynamics. A key aspect of SMD is Locational Marginal Prices (LMP), which factors into the ISO NE market prices the marginal transmission costs associated with serving a location demand. This is a key issue for the Cape Wind project, because the cost of resolving congestion in SEMA, i.e., the cost of a new 345 KV transmission line, uplift requirements, etc., will

[7] Depending upon the length of a 345 KV line expansion in SEMA, and the actual cost per mile, which NSTAR needs to disclose.

impact or be netted against LMP. The LaCapra report does not reflect or model current SMD and LMP practice in NEPOOL.

As a point of information, during the December 16th MIT hearing I had the opportunity to meet and speak with Mr. Douglas Smith, principal investigator for the LaCapra study. Mr. Smith confirmed that the scope of his effort was restricted to simply the old ISO NE wholesale energy market. He confirmed the LaCapra modeling/analysis did not capture the other ISO NE markets and associated costs such as uplift, spinning reserve, etc. The LaCapra report discusses on a "qualitative basis" an assertion that wind farm will meet "capacity" requirements (page 4), but as we know intermittent resources produce minimal capacity benefits. Also, Attachment 5 in the LaCapra report is outdated and misleading.[8]

Additional Operational NEPOOL Costs are Needed and are Material: For the DEIS "cost-benefit" analyses to be complete and accurate, it is important to identify associated NEPOOL costs because these must be "netted" against claimed annual savings. Since LaCapra fails to identify and analyze costs, the Cape Wind SIS or a specific consultant's study is greatly needed. And these costs are significant or "material." In fact, the associated costs could indeed offset or exceed the claimed savings.

To illustrate the importance and potential magnitude of these missing costs, I refer the ACOE to a "cost of operations" report released by The Royal Academy of Engineering (a copy enclosed for the ACOE review). The report shows that "standby generation" for offshore wind power in the United Kingdom can increase production costs by 30 percent. For the Cape Wind project this means that "standby generation" power and related costs could be $30 per MWH.[9] Given Cape Wind's representation that its power plant will produce approximately 1.5 million MWH per year, if ISO NE incurred an additional $30 per each MWH Cape Wind produced, the annual cost to ISO NE due to the wind farm integration would be $45 million. This $45 million of added cost to NEPOOL would far and away eliminate/offset the $25 million "benefit" estimated by LaCapra. In fact, properly stated, under such a situation, the Cape Wind power plant would be a "net" cost to ISO NE and NEPOOL. If costs exceed benefits, this would be a serious problem.

The Royal Academy study also raises an issue concerning the type of standby generation needed to support Cape Wind. It is possible that the standby generation would be fossil and thus Cape Wind would be causing emissions such as CO_2 and NO_x. This is another good reason the SIS is needed because it will address this problem.

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[8] During the EFSB Cape Wind was asked to produce updated analysis concerning the supply of renewable energy projects qualified to meet Mass RPS. Considerable renewable projects are being planned; other regions such as Quebec have announced new wind projects that will meet Mass RPS.

[9] The Royal Academy Report shows costs of offshore wind energy and related standby generation costs, which increase total cost by 30 percent. Cape Wind has represented to the public that the United States should follow Europe's lead in OFFSHORE wind farm development. We can certainly learn from the European/British experience. Thus, this incremental cost of standby energy needs can be used as a benchmark or proxy for understanding the added costs that should be factored into the Cape Wind analysis. Certainly it would be much better for Cape Wind to release the SIS as required and as promised during the EFSB.

The specific cost to ISO NE and NEPOOL could be different from that shown in the Royal Academy study. However, based on relevant European OFFSHORE wind farm experience, we can certainly understand that "material" costs are missing from the DEIS. The costs (capital and operational) that will be identified in the Cape Wind SIS have potential to completely eliminate the claimed "savings" in the energy market. And most certainly it is important for the ACOE to ensure that the entire analysis of both cost and benefits are produced for the DEIS, or a Supplemental DEIS.

The burden of proof rests with Cape Wind to demonstrate in an unbiased fashion that its proposed power plant will be a "net" benefit. To present only benefits, as LaCapra has done, without associated costs, is unacceptable and biased.

Release the Missing NEPOOL Costs for the Supplemental DEIS: As noted above, I support the CCC recommendation for a Supplemental DEIS. The associated added or incremental ISO NE/NEPOOL operational cost due to Cape Wind must be identified and included in the DEIS or Supplemental DEIS. The public deserves the opportunity to review these missing costs so there is an unbiased and credible cost-benefit analysis. The ACOE needs to include these costs to be certain the analyses are complete and accurate.

Topic 3: Missing Project Economics

Setting the Context: Finally, the DEIS is missing basic project and power plant economics. Identifying the total cost of electricity production from the wind farm is critical. The ACOE, CCC, MEPA and public need to know, and deserve to know whether the Cape Wind power plant will be economically viable. With the sizeable public subsidies, the federal production tax credit (PTC), and the Massachusetts RPS emission credits, and the "free" use of 24 square miles of public property, the public is effectively a "partner" in Cape Wind, LLC. As a "partner," the public has a right to review all the project economics. Cape Wind has an obligation to disclose an economic feasibility assessment. If the wind farm fails economically, then the long-term economic benefits claimed in the DEIS will not be realized. The public will not have a return on our investment.

I point out that "economics" is identified in the scope of work for the DEIS. On page 2-2 we find reference to Title CFR Part 320-4 that "All factors which may be relevant to the proposal [i.e., the Cape Wind project] must be considered including the cumulative effect thereof…economics." Cape Wind will receive public subsidies for this project, which is comparable to the issuance of a municipal revenue bond. A due diligence study is required to demonstrate bondholders will be paid. In this case, the DEIS is the "due diligence" to assure the public we will receive a return on the enormous public subsidies we will pay.

The "project economics" are missing; there is no due diligence. The ACOE needs ensure the public's interests are well served. The project economics should be included in the DEIS, or a Supplemental DEIS.

Independent Project Analysis are Available: Some time ago, the Alliance to Protect Nantucket Sound (Alliance) released for public review and comment a cost study called the Byron Report. This study assessed the total cost of new generation for a range of possible projects, and it showed that an OFFSHORE wind farm similar to the Cape Wind power plant would be very expensive. At that time the Byron Report showed the total cost of generation for OFFSHORE wind farms similar to the Cape Wind project would be at least $85 per MWH, the most expensive option. A copy of the Byron Report is enclosed for the ACOE.

During the EFSB hearing process new estimates of capital requirements were identified and the revised Byron analysis indicated an OFFSHORE wind farm would have a total cost position greater than $85 per MWH.[10]

Impact of EVA Report Shows Cape Wind Will Produce Less Energy: Additionally, the Alliance retained an expert consultant, Energy Ventures Analysis (EVA), to analyze the DEIS, to survey European OFFSHORE wind energy projects for actual operational data to compare with Cape Wind project assumptions, and to analysis the available wind speed data for the Cape Cod region to assess whether the Cape Wind power plant could produce the amount of electricity claimed (that is, could the Cape Wind project achieve the approximate 1.5 million MWH of production per year?).

The EVA report, which has been forwarded to the ACOE, concludes that the approximate 36 percent capacity factor Cape Wind has assumed for the wind farm power plant is grossly overstated. EVA estimates a more realistic range of electricity production of 1.0 million MWH per year to 1.2 million MWH. This range translates into capacity factors of 25 to 30 percent. This is a critical finding for several reasons.

First, if the wind farm does not produce the amount of electricity Cape Wind claims it will, the total cost of electricity production will be well above $100 per MWH. In fact, using the EVA range of production electricity from the Cape Wind power plant will cost at least $110 per MWH to $125 per MWH, based on "scaling" the findings of the Byron Report. The cost of electricity production will be even greater once Cape Wind and NSTAR incorporate the missing SIS and NEPOOL operational costs.[11]

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[10] During the EFSB hearing process, additional capital costs to the Cape Wind project were identified. The Alliance witness incorporated these costs.

[11] Given the high fixed capital costs for OFFSHORE wind power, low capacity factors can dramatically raise the estimated cost of production per MWH. In fact, less production means less total subsidy from the PTC, which materially impacts, in a negative way, the cost of production.

Second, EVA points out, the environmental benefits claimed by LaCapra/Cape Wind are grossly overstated. Less electricity production means less CO_2, SO_2, NO_x and particulate emission savings.

Third, Cape Wind has made representations to the public through media advertisements, a statement on its web site, etc., that the wind farm power plant will provide the Cape & Island with approximately three quarters of the region's energy needs. This representation is grossly overstated.

Related Issue, Legal Corporate Structure: Presently we know Cape Wind's legal structure is a limited-liability corporation, i.e., an LLC. If Cape Wind Associates, LLC is the sole entity that invests and develops the power plant, then this LLC must be profitable to capture the federal PTC subsidy. However, Cape Wind's web site indicates Energy Management, Inc. (EMI) is developing the project. This raises the question: Will the LLC take credit of the federal subsidy or will EMI? To which entity is the public making subsidies? Where is our money going?

It is common practice for the developing and/or owning LLC to sell federal tax credits to profitable or financing organizations. As was seen in the collapse of one energy concern, interlocking partnerships obfuscated financial matters including the flow of dollars. Our lesson learned again and again is that "full and complete disclosure" of all financial and economic facts is critical for investor protection. The public, which will provide millions of dollars in subsidies, is looking to ACOE to ensure Cape Wind's financing structures for basic project economic analyses are transparent. We are looking to the ACOE for full and complete disclosure and due diligence.

Related Issue, Performance Insurance: Cape Wind has represented to the public that wind energy is "reliable." However, on January 11, 2005, *The Boston Herald* quoted Cape Wind's director of regulatory affairs, Mr. Dennis Duffy, as saying the wind energy industry desperately needs insurance policies to protect against low wind periods when the power plant cannot produce. This is an apparent contradiction: are wind projects reliable or not? The article goes on to point out that securing such insurance is a serious issue, and one that must be resolved to attract investors. The public is certainly an investor in Cape Wind, and if additional insurance is needed to attract private capital, we, the public, need to better understand this issue. Cape Wind needs to inform us. We need to know the additional cost and "true risks" before ACOE commits us to this investment by issuing the permit.

Supplemental DEIS is Needed: As indicated above, I support the CCC recommendation for a Supplemental DEIS. This will allow time for Cape Wind to produce the project economics to assure the public, the ACOE, the CCC, and MEPA that indeed the project is viable. Cape Wind needs to identify the production costs and demonstrate with standard cash flow analysis that the project is viable and thus Cape Wind will be able to perform long term and provide the public (one of Cape Wind's partners) that there will be a return on investment, the claimed long-term benefits.

Summary

Despite the impressive size and scope of the DEIS, and the work it represents, there are at least three (3) important reports or analyses missing. For a complete and accurate DEIS, the ACOE needs to direct Cape Wind and its consultants to incorporate the SIS, the costs associated with NEPOOL operations, and the project economics.

Not only are these analyses needed for an unbiased and fair representation to the public, as I indicated above, these are needed for full disclosure of the SIS, NEPOOL costs, and project economics, which will show the power plant is perhaps not viable. If so, it appears there will not benefits claimed, and there will not be a return on the massive public subsidies.

I support the CCC recommendation for a supplemental DEIS. This supplemental report will afford us the opportunity to include the three reports/analyses identified above.

Thank you for your consideration.

Sincerely,

Glenn G. Wattley

Cc: Massachusetts Environmental Policy Act Office
Cape Cod Commission

Enclosures

NSTAR Presentation October 31, 2002
NYSERDA GE Report
Royal Academy of Engineering Report
Byron Report

Adams, Karen K NAE

From: Ggwattley@aol.com

Sent: Thursday, February 24, 2005 5:35 PM

To: Energy, Wind NAE

Cc: anne.canaday@state.ma.us; pdascombe@capecodcommission.org

Subject: Comment on Cape Wind DEIS: Missing SIS, NEPOOL and Project Costs

Ms. Kirk-Adams:

As mentioned in my previous e-mail I have four reports I wish to enclose with the letter I sent concerning the above topic. The electronic size of these reports requires them to be e-mailed separately.

I apologize for the inconvenience.

The first enclosure (attachment) is an NSTAR presentation addressing the System Impact Study (SIS). This presentation was provided at the first ESFB hearing for the permit for the two (2) 115 KV underwater cables.

Thank you for your consideration, Glenn Wattley

Cape & Islands Electric Supp

Cape Wind Project Impact

10/31/2002

Presented by Charlie Salamone

Discussion Overview

- Cape & Island Electric Use
- Existing Generation and Transmission Supply Syster
- Impact Assessments for New Resource Interconnecti
- Standards of Review for New Interconnections
- Interconnection Review Schedule

NSTAR

Cape & Islands Electric Us

- Cape summer peak loads have grown by over 100 M since 1997 (growth rate of over 5% per year)
  - 1997 Summer Peak : 342 MW
  - 2002 Summer Peak : 446 MW
- Total peak load supplied by the Cape transmission sy includes:
  - 42 MW for supply to Martha's Vineyard
  - 34 MW for supply to Nantucket
  - 404 MW for supply to Cape mainland
- Average load on the system is over 230 MW and tota energy delivered by the Cape transmission system is approximately 2.0 GWH

NSTAR

Existing Transmission Syste

- Existing transmission system operates at 115 and 345 kV voltages
- Two 345 kV lines crossing the Cape Cod can each are capable of carrying 1000 MW of loa
- Two 115 kV lines crossing the canal each are capable of carrying 225 MW of load
- The Canal generating plant can deliver 1100 of capacity to the system
- The Pilgrim generating plant can deliver 660 of capacity to the system

NSTAR


PILGRIM STATION
CLEARY STATION
SEMASS PLANT
CANAL PLANT
MONTAUP
BRAYTON
DARTMOUTH POWER
FALMOUTH

NSTAR

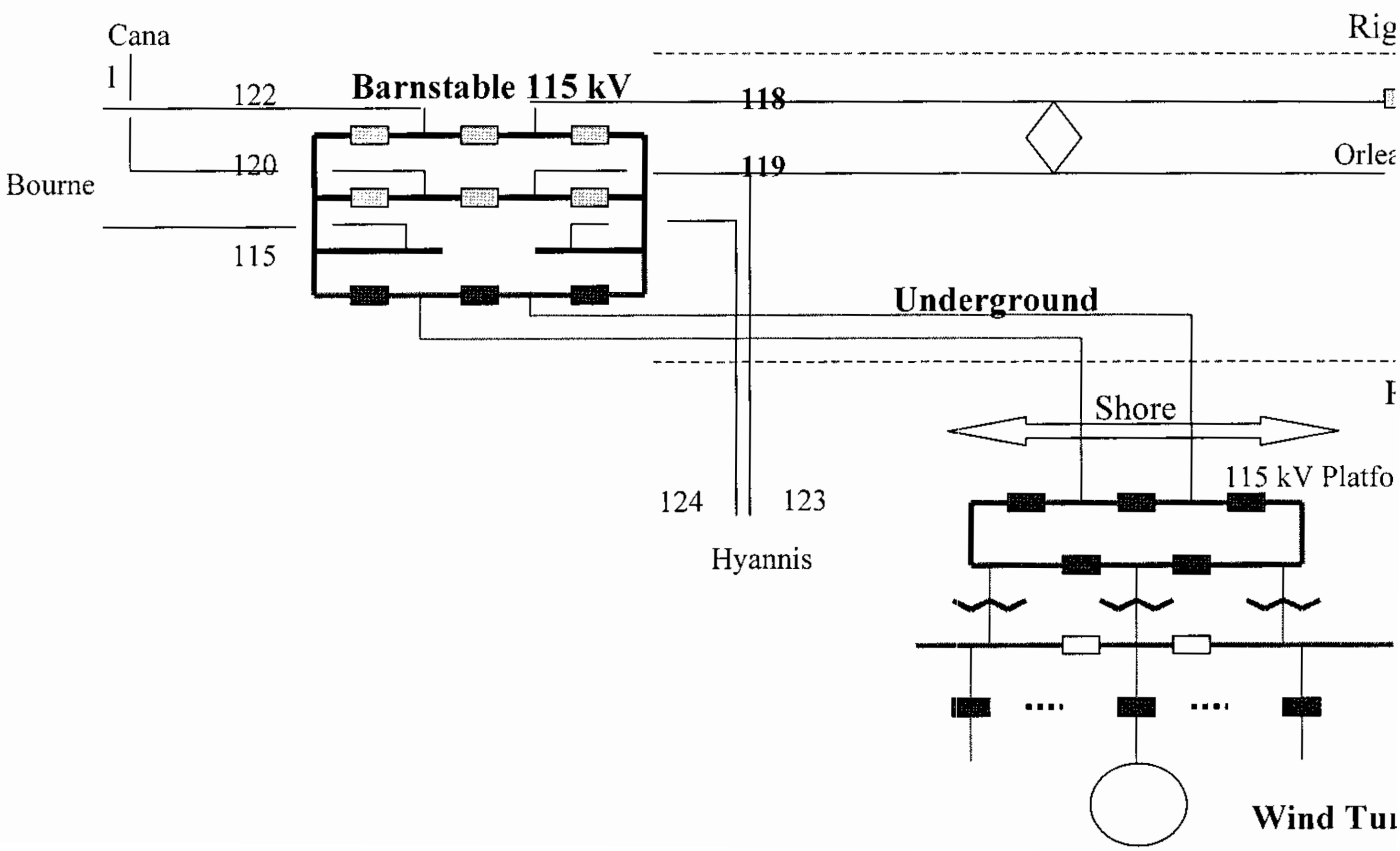
Impact Assessments for New Resource Interconnections

- Federal regulations obligate us to interconnec generator as long as all impacts to the transm system are mitigated
- NSTAR follows pre-established rules and wo in concert with ISO-New England in assessin impacts of the generator
- A complete analysis of the operational, stead state as well as second-by-second electrical ir of the plant and its interconnection are thorou studied

NSTAR

Proposed Interconnection

FIGURE 1 – Cape Wind Interconnection Alternative 1



NSTAR

Standard of Review

- Standards that must be met include:
  - Northeast Power Coordinating Council Reliability Standard
  - New England Power Pool Reliability Standards
  - NSTAR Reliability Standards
  - ISO Minimum Interconnection Standard
- Reviewing bodies include:
  - DTE / Siting Board
  - ISO New England
  - Transmission Task Force (NE Transmission & Generation
  - Stability Task Force (NE Transmission & Generation owne
  - NEPOOL Reliability Committee
  - FERC

NSTAR

Interconnection Review Schec

- Study efforts are currently under way
- Detailed simulation models are under development for use in system impact studies
- Study work will take from 6 to 8 months to complete
- Review process will take from 2 to 3 months complete
- Final approval of the interconnection by NEP and ISO-NE would be possible in about 1 yea

Electric System Impacts

- Positive Impacts
  - Additional system resource
  - Fuel diversity
  - Cape transmission system voltage support
- Potential Concerns
  - Dynamic response
  - Protection system coordination

Adams, Karen K NAE

From: Ggwattley@aol.com
Sent: Thursday, February 24, 2005 5:36 PM
To: Energy, Wind NAE
Cc: anne.canaday@state.ma.us; pdascombe@capecodcommission.org
Subject: Comment on Cape Wind DEIS: Missing SIS, NEPOOL and Project Costs

Ms. Kirk-Adams:

Attached below is the second enclosure for my letter that address the above.

It is a NYSERDA-GE report on the technical problems that must be addressed to integrate wind farms to a high-voltage transmission grid.

Again, I am sorry these enclosures must be sent separately.

Glenn Wattley

THE EFFECTS OF INTEGRATING WIND POWER ON TRANSMISSION SYSTEM PLANNING, RELIABILITY, AND OPERATIONS

Report on Phase 2:

System Performance Evaluation

Prepared for:

THE NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Albany, NY

John Saintcross
Project Manager

Prepared by:

GE ENERGY

ENERGY CONSULTING

Richard Piwko, Project Manager
Xinggang Bai
Kara Clark
Gary Jordan
Nicholas Miller
Joy Zimberlin

DRAFT

February 3, 2005

Foreword

This document was prepared by General Electric International, Inc. in Schenectady, NY. It is submitted to THE NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA). Technical and commercial questions and any correspondence concerning this document should be referred to:

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1 Introduction

1.1 Background

In response to emerging market conditions, and in recognition of the unique operating characteristics of wind generation, the New York Independent System Operator (NYISO) and New York State Energy Research and Development Authority (NYSERDA) commissioned a joint study to produce empirical information that will assist the NYISO in evaluating the reliability implications of increased wind generation. The work was divided into two phases.

Phase 1, Preliminary Overall Reliability Assessment, was completed in early 2004. This initial phase provided a preliminary, overall, screening assessment of the impact of large-scale wind generation on the reliability of the New York State Bulk Power System (NYSBPS). This assessment included:

- Review of world experience with wind generation, focusing on regions that have integrated significant penetration of wind resources into their power grids
- Fatal flaw power flow analysis to determine the maximum power output at prospective wind generation sites that can be accommodated by the existing transmission system infrastructure, considering thermal ratings of transmission lines
- Reliability analysis to determine the contribution of prospective wind generation towards meeting New York State requirements for Loss Of Load Expectation (LOLE)
- Review of current planning and operating practices to identify New York State Reliability Council (NYSRC), Northeast Power Coordinating Council (NPCC), North-American Electric Reliability Council (NERC), and NYISO rules, policies, and criteria that may require modification to be compatible with high penetration of wind generation

Phase 2 builds on what was learned in Phase 1. A base case wind scenario with 3,300 MW of wind generation (10% of NY State peak load) was selected for analysis. Operation of the NYSBPS with 3,300 MW of wind was evaluated in numerous ways, considering impacts on the following aspects of grid performance:

- Reliability and generation capacity
- Forecast accuracy
- Operation of day-ahead and hour-ahead markets
- Economic dispatch and load following
- Regulation
- Stability performance following major disturbances to the grid.

Results of these Phase 2 analyses are presented in this report.

1.2 Wind Generation Scenario

Starting from the original 10,026 MW of wind generation at 101 sites evaluated in Phase 1, two alternate scenarios with 3,300 MW of wind generation were considered. The project team selected a scenario with 3,300 MW of wind generation in 33 locations across New York State. Table 1.1 shows the location (by zone) of the wind farms included in the study. The lower portion of Table 1.1 lists the "Superzones" used by NY State Department of Public Service (DPS) for the RPS study. Load zones within the New York Control Area are illustrated in Figure 1.1.

The wind generation in Zone K, Long Island, is located offshore. The rest of the sites are land-based wind farms. The 600 MW site in Zone K was divided into 5 separate wind farms for interconnection into the Long Island transmission grid. Thus, the 33 wind sites are modeled in loadflow and stability simulations as 37 individual wind farms.

As a point of reference, the NYISO queue of proposed new generation presently has a total of 1939 MW in wind projects.

Table 1.1 Study Scenario – Wind and Load MW by Zone

	Total Potential Wind Generation	2008 Noncoincident Peak Load	Wind MW in Study Scenario	Wind as % of Peak Load
Zone A	3,070	2,910	684.2	24%
Zone B	1,197	2,016	358.5	18%
Zone C	1,306	2,922	569.7	19%
Zone D	483	902	322.6	36%
Zone E	2,832	1,592	399.8	25%
Zone F	434	2,260	260.6	12%
Zone G	105	2,260	104.6	5%
Zone H	0	972	0.0	0%
Zone I	0	1,608	0.0	0%
Zone J	0	11,988	0.0	0%
Zone K	600	5,275	600.0	11%
sum	10,026	34,704	3300.0	10%
DPS Zn 1	8,887	10,342	2334.8	23%
DPS Zn 2	538	7,099	365.2	5%
DPS Zn 3	600	17,263	600.0	3%
sum	10,026	34,704	3300.0	10%

Notes: DPS Zn 1 = Zones A + B + C + D + E
DPS Zn 2 = Zones E + F + G + H
DPS Zn 3 = Zones I + K

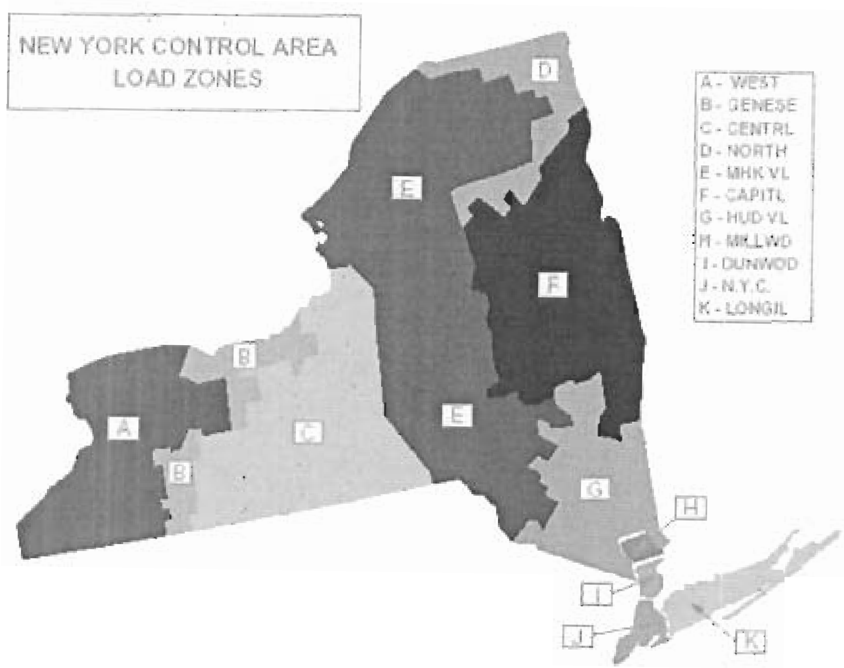

Figure 1.1 New York Control Area Load Zones

The majority of the wind generation in the study scenario is located in upstate NY, Zones A through E. In those zones, penetration of wind generation is 23% of peak zonal load. The 600 MW of offshore wind generation in Zone K represents 11% of peak load in that zone.

The model of the New York State Bulk Power System (NYSBPS) used in this study was derived from NYISO's 2008 transmission and generation modeled. Zonal load profiles were derived from measured data from years 2001-2003, scaled upward to be consistent with projected load levels in 2008.

Wind turbine-generators were assumed to have characteristics consistent with present state-of-the-art technology, and included continuously controllable reactive power capability (0.95 power factor at point of interconnection), voltage regulation, and low-voltage ride-through (LVRT).

1.3 Timescales for Power System Planning and Operations

The power system is a dynamic system, subject to continuously changing conditions, some of which can be anticipated and some of which cannot. The primary function of the power system is to serve a continuously varying customer load. From a control perspective, the load is the primary independent variable – the driver to which all the controllable elements in the power system must be positioned and respond. There are annual, seasonal, daily, minute-to-minute and second-to-second changes in the amount (and character) of load served by the system. The reliability of the system then becomes dependent on the ability of the system to accommodate expected and unexpected changes and disturbances while maintaining quality and continuity of service to the customers.

As illustrated in Figure 1.2, there are several time frames of variability, and each time frame has corresponding planning requirements, operating practices, information requirements, economic implications and technical challenges. Much of the analysis presented in this report is aimed at quantitatively evaluating the impact of significant wind variability in each of the time frames on the reliability and performance of the NYSBPS.

Figure 1.2 shows four timeframes covering progressively shorter periods of time. In the longest timeframe, planners must look several years into the future to determine the infrastructure requirements of the system. This timeframe includes the time required to permit and build new physical infrastructure. In the next faster timeframe, day-to-day planning and operations must prepare the system for the upcoming diurnal load cycles. In this time frame, decisions on unit commitment and dispatch of resources must be made. Operating practices must ensure reliable operation with the available resources. During the actual day of operation, the generation must change on an hour-to-hour and minute-to-minute basis. This is the fastest time frame in which economics and human decision-making play a substantial role. Unit commitment and scheduling decisions made the day ahead are implemented and refined to meet the changing load. In NY State, the economic dispatch process issues load following commands to individual generators at 5-minute intervals. In the fastest time frame (at the bottom of the figure), cycle-to-cyle and second-to-second variations in the system are handled primarily by automated controls. The system automatic controls are hierarchical, with all individual generating facilities exhibiting specific behaviors in response to changes in the system that are locally observable (i.e. are detected at the generating plant or substation). In addition, a subset of generators provide regulation by following commands from the centralized automatic generation control (AGC), to meet overall system control objectives including scheduled interchange and system frequency.

Time Frame	*Planning and Operation Process*	*Technology Issues*
Slower (Years)	**Resource and Capacity Planning** **(Reliability)**	**Capacity Valuation (UCAP, ICAP) and Long-Term Load Growth Forecasting**
	Unit Commitment and Day-Ahead Scheduling	**Day-ahead and Multi-Day Forecasting**
	Load Following (5 Minute Dispatch)	**Hour-Ahead Forecasting and Plant Active Power Maneuvering and Management**
Faster (Seconds)	**Frequency and Tie-Line Regulation (AGC)**	**Real-Time and Autonomous Protection and Control Functions (AGC, LVRT, PSS, Governor, V-Reg, etc.)**

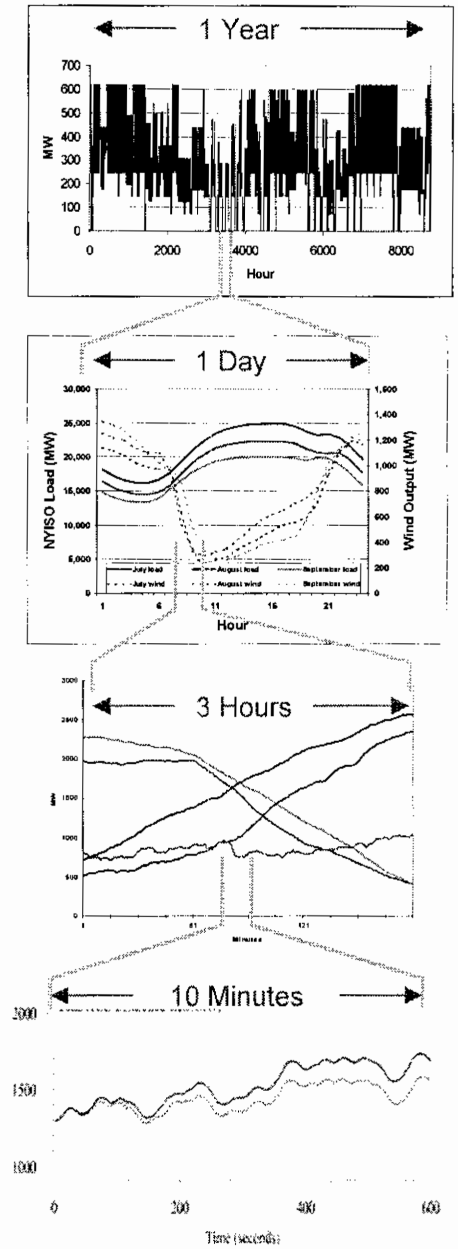

Figure 1.2 Time Scales for System Planning and Operation Processes

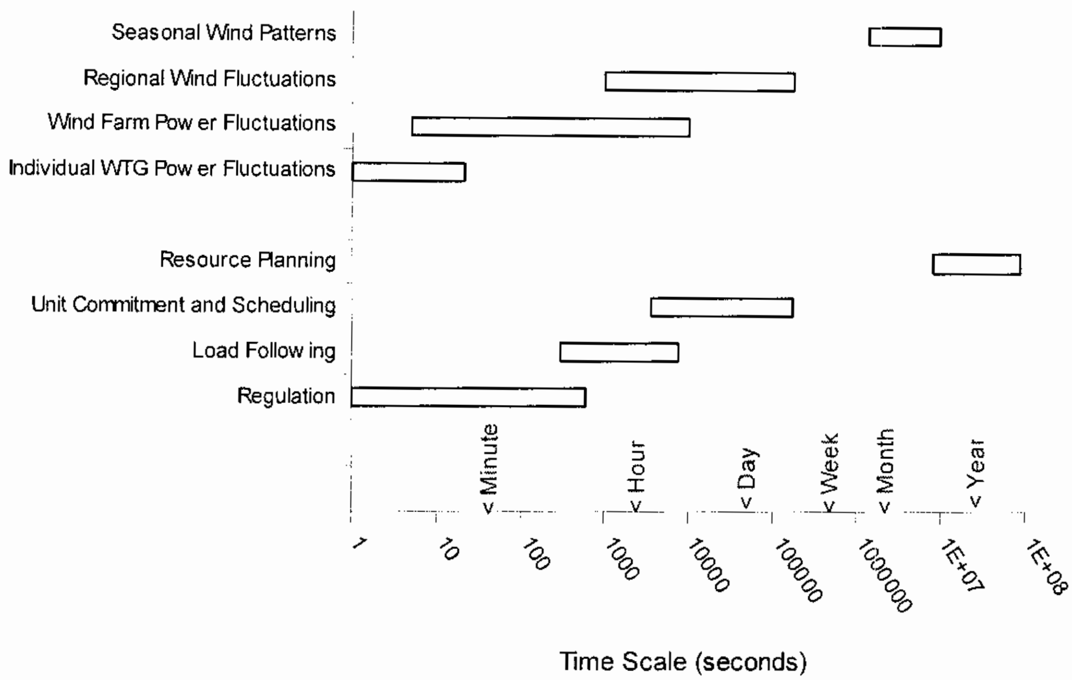

Figure 1.3 Wind Variability and Impact on System Operation Processes

Wind, as a variable and largely undispatchable generating resource, will impact all of these planning and operation processes. Wind variability has its own characteristics and time frames. As with system load, there are seasonal, diurnal, hour-to-hour , minute-to-minute and second-to-second variations. In the case of wind generation, as the time frame decreases the correlation between wind generating resources drops.[i] This is shown in the upper portion of Figure 1.3, where the spatial aspect of wind variation is correlated to the time-scale of temporal variations. Individual wind turbine-generators (WTGs) commonly experience power output variations in the one-second to several-minute timeframe. When many WTGs are grouped together in a wind farm, the short-term variations of individual WTGs are attenuated as a percentage of the aggregate, and the dominant power output variations for the entire wind farm occur in the minute-to-hour time frame. Similarly, the minute-to-minute power output of individual wind farms are attenuated in systems with multiple wind farms, leaving regional wind fluctuations in the hour-to-day time frame as the dominant system-wide effect. Seasonal wind patterns, of course, fall into the several-month timeframe.

The lower portion of Figure 1.3 shows how these wind variations relate to the four groups of planning and operation processes identified in Figure 1.2.

1.4 Technical Approach

The technical approach for this project addresses the range of processes involved in the planning and operation of the NYSBPS, over the range of timescales from seconds to years. The bulk of the technical analysis was grouped into four major areas as described below.

1.4.1 Forecast Accuracy

The accuracy of the wind forecast affects unit commitment and operating reserve policies. Accuracy of wind generation forecasting was evaluated, and related to the historical accuracy of load forecasts used in the day-ahead market.

1.4.2 Wind and Load Variability

The NYSBPS already deals with significant variability in system load. Wind generation, as a variable power source, adds to the total variability that the NYSBPS must accommodate. The analysis of variability addressed the both major contributors to variability over several time frames:

Variability:

- Variability due to load alone
- Variability due to wind alone
- Combined variability due to load and wind, synchronized over the same calendar periods.

Time Frames:

- Hourly
- 5-minutes (load-following; economic dispatch)
- Seconds (regulation, AGC)

This analysis used consistent sets of historical wind data and historical load data, for the same time periods.

1.4.3 Operational Impact

Operational impacts cover a range of time scales, from seconds to multiple hours. Operation of the NYSBPS was simulated with and without wind generation (per the study scenario) as follows:

- Simulation of statewide operations for an entire year using MAPS, focusing on dispatch and unit commitment issues as a function of wind forecast accuracy.

- Quasi-steady-state simulation of selected 3-hour periods for wind and load variability, focusing on issues that affect load following.
- Stability simulation of selected 10-minute periods, focusing on regulation and other short-term control and protection issues (voltage regulation, low-voltage ride-through, AGC, etc.)

1.4.4 Effective Capacity

Using the Multi-Area Reliability Simulation (MARS) program, the effective capacity of wind generation, was quantified by comparing it with a typical fossil-fired power plant. This analysis includes consideration of the seasonal and diurnal variability in wind generation output relative to periods of peak system load, when generating resources have the greatest impact of overall system reliability as measured by loss-of-load probability (LOLP).

In addition to quantifying the likely range of unforced capacity (UCAP) for wind generation in NY State, approximate techniques for calculating the UCAP of individual wind farms were developed.

1.5 Data

Technical information and data for this study were obtained from the following sources:

- NYISO provided power flow and stability datasets, historical operating data for years 1999-2003, and contingency lists for the NYSBPS and NYSRC reliability datasets.
- AWS TrueWind provided data on potential wind generation sites in NY State, wind MW generation at those sites based on historical weather data, and technical information related to wind generation and wind forecasting.
- NYSDPS provided generation fuel cost and heat rate data from the preliminary RPS analyses.

Appendix A contains detailed descriptions of data provided by NYISO and AWS TrueWind.

2 Executive Summary

This study evaluated the impact of wind generation on the New York State Bulk Power System (NYSBPS) over a broad range of subject areas, including planning, operation, economics, and reliability. Key results and conclusions are summarized here. Details of the analysis, and the reasoning behind the conclusions, are further explained in Chapters 3-8.

2.1 Study Scenario for Wind Generation

The technical analysis for this study focused on a wind generation scenario that included a total of 3,300 MW of wind generation in 33 locations throughout New York State (see Table 2.1). Most of the wind sites are located upstate, but there is one large offshore facility near Long Island (Zone K). The total amount of wind generation (nameplate rating) in this scenario corresponds to approximately 10% of New York State's 2008 projected peak load.

Table 2.1 Wind Generation Included In Study Scenario

Location	Wind Generation MW	Wind Generation as % of 2008 Peak Load
Zone A	684.2	24%
Zone B	358.5	18%
Zone C	569.7	19%
Zone D	322.6	36%
Zone E	399.8	25%
Zone F	260.6	12%
Zone G	104.6	5%
Zone H	0.0	0%
Zone I	0.0	0%
Zone J	0.0	0%
Zone K	600.0	11%
Total for NY	3300.0	10%

Powerflow and operational models for the study scenario were derived from NYISO's 2008 system model. Hourly and shorter-term load profiles were based on actual historical data from years 2001-2003, but were scaled to match the projected load for 2008. Profiles of wind generation at the 33 locations were derived from historical weather records for years 2001-2003, so wind generation in the study scenario was treated as though the wind generators were actually in operation during those years.

Observations and conclusions presented in this report are based on analysis of this study scenario.

2.2 Impact on System Planning

A wide variety of standards, policies and criteria were reviewed to assess their impact on wind generation, and to determine if changes were needed to accommodate wind generation. In general, it was found that the existing rules and criteria could be applied to wind generation. A few specific items are discussed below.

2.2.1 NYISO System Reliability Impact Study (SRIS)

NYISO's SRIS is intended to confirm that a new facility complies with applicable reliability standards, to assess the impact of the new facility on the reliability of the pre-existing power system, to evaluate alternatives for eliminating adverse impacts (if any), and assess the impact of the new facility on transmission transfer limits. The SRIS policy is directly applicable to wind generation in its present form.

2.2.2 NYSRC Reliability Rules for Planning and Operation

NYSRC reliability rules are outlined in the document *NYSRC Reliability Rules for Planning and Operating the New York State Power System*, which addresses both resource adequacy and system security. A few minor changes related to planning studies are recommended:

The rules for steady-state analysis require evaluation of single-element (N-1) and extreme contingencies. Normally, loss of one generator in a multi-generator power plant would be a single-element contingency. Wind farms are comprised of many wind turbine-generators connected to a common interconnection bus. It is recommended that the loss of the entire wind farm be considered a single-element contingency for the purpose of NYSRC reliability criteria. However, simultaneous loss of multiple wind farms due to loss of wind in not a credible event. No changes to NYSRC rules for extreme contingencies, or multiple-element outages, are recommended.

NYSRC rules for stability analysis require evaluation of both design criteria and extreme faults. No changes to these rules or their interpretation are required for wind generation.

2.2.3 Generation Interconnection Requirements

In the Phase 1 report, it was recommended that New York State adopt some of the interconnection requirements that have emerged from the experiences of other systems. Specifically, New York State should require all new wind farms to have the following features:

- Voltage regulation at the Point-Of-Interconnection, with a guaranteed power factor range (±0.95 is recommended)
- Low-voltage ride-through (LVRT)
- A specified level of monitoring, metering, and event recording
- Power curtailment capability (enables system operator to impose a limit on wind farm power output)

The above features are implemented in wind farms around the world, and are proven technology.

During Phase 2, technical analysis was performed to evaluate some of these features with respect to performance of the NYSBPS. Specifically, the impact of voltage regulation and low voltage ride through (LVRT) on system performance was demonstrated. The results showed that voltage regulation with a ±0.95 power factor range improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. In addition, LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances, and mitigates concerns about loss of multiple wind farms due to system events. Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. It is recommended that New York adopt the emerging LVRT specification.

No operating conditions were found to justify the need for wind power curtailment at a statewide level. However, NYISO should require a power curtailment feature on new wind farms as a mechanism to posture the power system to handle temporary local transmission limitations (e.g., line out of service) or in anticipation of severe weather (e.g., intentionally curtail wind generation in advance of a severe storm affecting a large portion of the state).

Interconnection requirements are different for each transmission owner in New York State. In general, standards for interconnection of wind turbines are the same as for other generation. Thus, frequency and voltage ranges, power factor ranges and other protection requirements remain largely unchanged. However, some features, such as governor control and power system stabilizer (PSS), are either technically impractical now or inappropriate for wind generators.

2.2.4 Future Interconnection Options

In the Phase 1 report, the following features were identified as emerging in response to system needs, and should be considered by New York State in the future as they become available:

- Ability to set power ramp rates

- Governor functions
- Reserve functions
- Zero-power voltage regulation

During Phase 2, technical analysis was performed to evaluate one of these features with respect to performance of the NYSBPS. Specifically, the ability to set power ramp rates for wind farms was demonstrated. The example ramp rate limit function resulted in a decrease in statewide regulation requirements at the expense of wind energy production. Therefore, such a function should only be used in specific applications to ensure system reliability.

2.3 Impact on System Operations

Table 2.2 provides a condensed summary of many key study results, arranged according to time scale. The following sections discuss each item in detail.

Table 2.2 Summary of Key Analytical Results for Study Scenario

Time Scale	Technical Issue	Without Wind Generation	With Wind Generation	Comme
Years	UCAP of Wind Generation	$UCAP_{land\text{-}based} \cong 10\%$ $UCAP_{offshore} \cong 36\%$ (one site in L.I.)		• UCAP is site-specific • Simple calculation method
Days	Day-Ahead Forecasting and Unit Commitment	Forecasting error: $\sigma \cong$ 700-800 MW	Forecasting error: $\sigma \cong$ 850-950 MW	• Incremental increase can b existing processes and res • Even without forecasts, wi conventional generation, re costs, and reduces emissic • Accurate wind forecasts ca another 30%
Hours	Hourly Variability	σ = 858 MW	σ = 910 MW	• Incremental increase can b existing processes and res
	Largest Hourly Load Rise	2575 MW	2756 MW	• Incremental increase can b existing processes and res
Minutes	Load Following (5-min Variability)	σ = 54.4 MW	σ = 56.2 MW	• Incremental increase can b existing processes and res
Seconds	Regulation	225 to 275 MW	36 MW increase required to maintain same performance	• NYISO presently exceeds • May still meet minimum NE regulating capability
	Spinning Reserve	1200 MW	1200 MW	• No change to spinning rese
	Stability	8% post-fault voltage dip (typical)	5% post-fault voltage dip (typical)	• State-of-the-art wind gener in power swings, and impr of the interconnected powe

Note: σ = standard deviation

2.3.1 Forecasting and Market Operations

NYISO's day-ahead market presently uses day-ahead load forecasts as part of the generation commitment and scheduling process. The error between forecast load and actual load introduces a level of uncertainty that must be accommodated by NYISO's operating practices. Wind generation introduces another element of uncertainty. Analysis of wind forecast performance for the study scenario shows that errors in day-ahead wind generation forecasts have standard deviations of approximately 400 MW, or 12% of the aggregate rating of all the wind generators (3,300 MW).

Figure 2.1 shows the standard deviations of load forecast error, wind forecast error, and combined "Load minus Wind" forecast error for 11 selected months of years 2001-2003. The figure shows that total forecasting error (Load-Wind) is somewhat higher than the forecasting error due to load alone. For example, in the peak load months (points on the right-hand side), the total forecast error increases from 700-800 MW without wind generation (Load alone) to 850-950 MW with 3,300 MW of wind generation (Load-Wind). NYISO operational processes to deal with uncertainty in load forecasting already exist. The same processes can be used to handle the increase in forecast uncertainty due to wind generation.

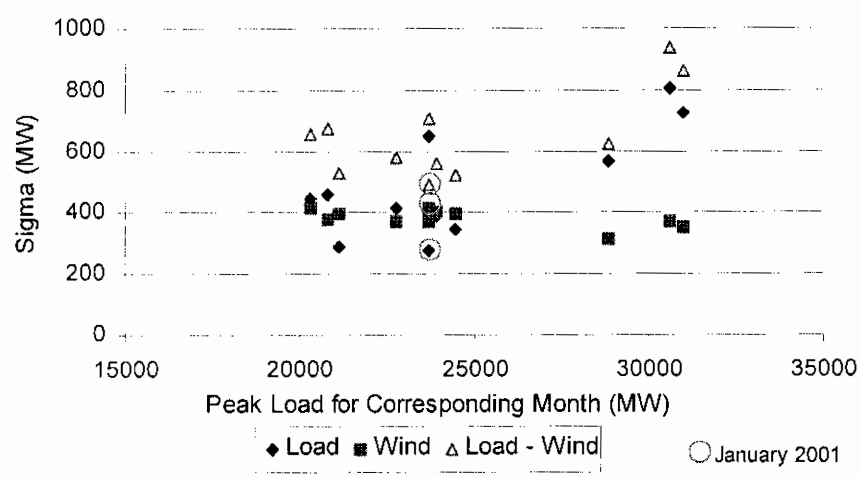

Figure 2.1 Standard Deviation of Day-Ahead Forecast Errors

Accuracy of wind forecasts improves as the lead-time decreases. For the study scenario, errors in hour-ahead wind generation forecasts are expected to have standard deviations of approximately 145 MW, or 4.2%.

Wind forecast uncertainties are of sufficient magnitude at the levels of penetration examined in this study to warrant the use of state-of-the-art forecasting. Data collection from existing and new wind farms should proceed immediately, in order to provide input to, and increase the fidelity of, wind forecasts for when the system achieves higher levels of penetration. New York should also consider meteorological data collection and analysis from proposed and promising wind generation locations in order to aid and accelerate the integration of high fidelity wind forecasting into NYISO's operating practices.

The existing day-ahead and hour-ahead energy markets in New York have sufficient flexibility to accommodate wind generation without any significant changes. It may be appropriate for some of the wind, for example 75% of the forecast, to bid into the day-ahead market while the balance can be bid into the short-term market. In order to take advantage of the spatial diversity of multiple plants, it may also be appropriate to aggregate wind generation on a zonal or regional basis rather than treating them as individual plants.

Wind forecasting may be performed in either a centralized or decentralized manner. With either approach, forecasts would be generated for each individual wind farm. However, centralized wind forecasting has several advantages that the NYISO may wish to consider:

- Application of a consistent methodology, which should achieve more consistent results across projects
- More effective identification of approaching weather systems affecting all wind plants, to warn the ISO of impending large shifts in wind generation
- Use of data from each plant to improve the forecasts at other plants. For example, a change in output of one plant might signal a similar change in other plants downstream of the first. Individual forecasters would not have access to the data from other projects to make this possible.

Care should be taken in the structuring of any financial incentives that may be offered to encourage the development of wind generation. The market for wind generation (including incentives) should be structured to:

- reward the accuracy of wind generation forecasts, and
- encourage wind generators to curtail production during periods of light load and excessive generation.

The second item above is particularly critical to overall system reliability. If excessive wind generation causes the NYISO is forced to shut down critical base-load generators with long shutdown/restart cycle times, the system could be placed in a position of reduced reliability. The market for wind power should be structured so that wind generators have clear financial incentives to reduce output when energy spot prices are low (or negative).

2.3.2 Hourly Variability

Load and wind production vary from day-to-day and hour-to-hour, exhibiting characteristic diurnal patterns. The wind variability increases the inherent variability that already exists due to loads. Table 2.3 shows the changes in hourly variability due to the addition of wind generation, expressed as standard deviations (σ).

Table 2.3 Hourly Variability With and Without Wind Generation

	Without Wind	With Wind	Increase
Statewide	858 MW	910 MW	6%
Superzone A-E	268 MW	313 MW	17%
Zone K	149 MW	171 MW	15%

System operators give special attention to periods of peak demand and rapid rise in load. The summer morning load rise, especially during periods of sustained hot weather, presents one of the more severe tests to the system. Figure 2.2 shows the hour-to-hour variability for the load rise period for mornings during June through September. The natural diurnal tendency for wind generation to fall off during this period causes higher rates of rise. In this sample, 31% of the hours have rise rates greater than 2,000 MW/hr without wind, with the worst single hour rising 2,575 MW. With the addition of wind generators, this increases to 34% of hours with rise rates greater than 2,000 MW/hr, and the worst single hourly rise is 2,756 MW. Existing NYISO operating practices are expected to accommodate this increase.

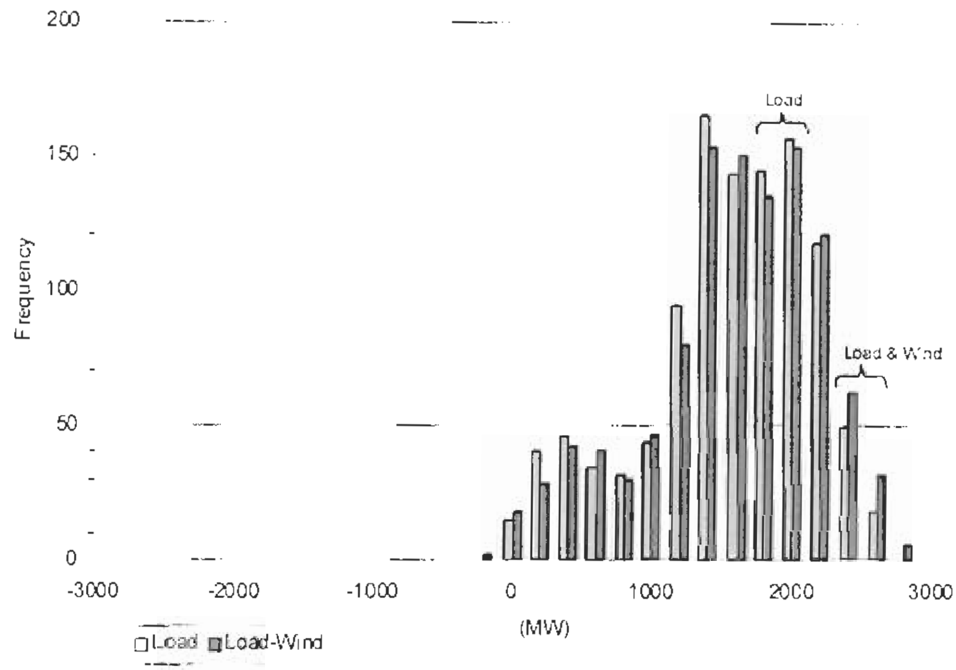

Figure 2.2 Summer Morning Load Rise - Hourly Variability

2.3.3 Load-Following

The impact of 3,300 MW of wind generation imposed on existing load-following performance was evaluated by both statistical analysis and time-response simulations.

NYISO sends economic dispatch commands to generators at 5-minute intervals. Statistical results are summarized as a histogram in Figure 2.3, showing the distribution of 5-minute changes in load with and without wind. These results indicate that wind generation would introduce only a small increase in the load-following duty for generators on economic dispatch. The standard deviation of the statewide samples increases by 1.8 MW (3%), from 54.4 MW without wind generation to 56.2 MW with wind generation.

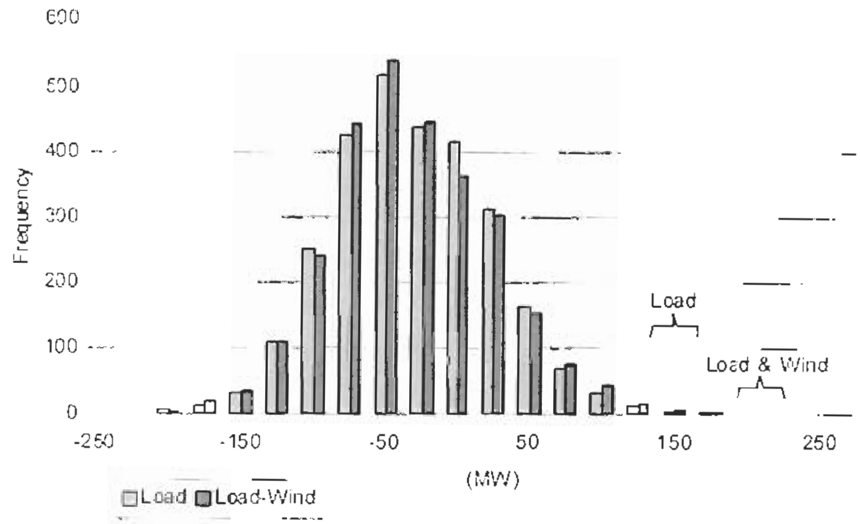

Figure 2.3 Five-Minute Statewide Variability

Quasi-steady-state (QSS) time simulations were performed to evaluate load-following performance during selected periods when both load and wind experienced large changes (e.g., rising load while wind generation declines, and vice-versa). The simulations were for load and wind profiles near the upper extremes of both Figure 2.2 and Figure 2.3, as indicated by the annotations on the figures. The results show that the existing economically dispatched generators would accommodate the increase in load-following duty.

2.3.4 Regulation

NYISO's automatic generation control (AGC) system maintains intertie flows and system frequency by issuing power commands to the regulating units at 6-second intervals. Existing operating practices require 225 MW to 275 MW of regulating units on-line, depending on the season. The impact of 3,300 MW of wind generation imposed on the existing regulating scheme was evaluated by both statistical analysis and stability simulations.

The statistical analysis of the study scenario shows that the standard deviation (σ) of 6-second variability due to load alone is 71 MW. As a check of existing regulation practice, this result suggests that 3σ, or 213 MW, of regulation would cover 99.7% of the time. With the addition of 3,300 MW of wind generation, the standard deviation increases from 71 MW to 83 MW. This implies that a 36 MW (3σ) increase in regulating capability will maintain the existing level of regulation performance with the addition of 3,300 MW of wind generation. Stability simulations covering selected 10-minute periods produced similar results.

This conclusion is further reinforced by the results of the 5-minute variability analysis. Variations in periods less than five minutes are addressed by regulation, while longer-term variations are addressed by economic dispatch (load-following). The analysis shows the standard deviation of combined load and wind variability for 5-minute periods is 56.2 MW (up from 54.4 MW due to load alone).

NYISO regulation performance (CPS1 and CPS2) presently exceeds NERC criteria. It is possible that the NYISO grid could accommodate 3,300 MW of wind generation with no increase in NYISO's regulation capability, and still meet minimum NERC criteria.

2.3.5 Spinning Reserves

Spinning reserves are required to cover the largest single contingency that results in a loss of generation. The present requirement is 1,200 MW. Analysis of historical statewide wind data indicates that loss of wind generation due to abrupt loss of wind in not a credible contingency, and hence, the spinning reserve requirement would not be affected. Short-term changes in wind are stochastic (as are short-term changes in load). A review of the wind plant data revealed no sudden change in wind output in three years that would be sufficiently rapid to qualify as a loss-of-generation contingency.

2.3.6 System Operating Costs

GE's Multi-Area Production Simulation (MAPS) program was used to simulate the hourly operation of the NYSBPS for several years, with and without wind generation per the study scenario. Several different techniques for integrating wind generation into NYISO's unit commitment and day-ahead market were considered. The most likely approach involves using day-ahead wind generation forecasts for the unit commitment process, and scheduling wind generation before hydro. The process essentially shifts hydro generation within a several day period to make the best use of wind resources when they are available. Operating cost impacts for this approach are summarized in Table 2.4, based on the 2001 historical hourly load and wind profiles. (Note: System-wide impacts include NYISO, ISO-NE, and PJM.) The MAPS simulation results also indicate a $1.80/MWh average reduction in spot price in New York State.

Table 2.4 Annual Operating Cost Impacts for 2001 Wind and Load Profiles
(Unit commitment based on wind generation forecast)

	System-Wide	**NYISO**
Total variable cost reduction *(includes fuel cost, variable O&M, start-up costs, and emission payments)*	$ 430M	$ 350M
Total variable cost reduction per MW-hour of wind generation	$48 / MWh	$39 / MWh
Wind revenue	$ 315M	$ 315M
Non-wind generator revenue reductions	$ 795M	$ 515M
Load payment reductions *(calculated as product of hourly load and the corresponding locational spot price)*	$ 515M	$ 305M

The operating costs depend on how the wind resources are treated in the day-ahead unit commitment process. If wind generation forecasts are not used for unit commitment, then too many units are committed and efficiency of operation suffers. The operating costs for this situation are summarized in Table 2.5. In this case, unit commitment is performed as if no wind generation is expected, and wind energy just "shows up" in the real time market. The results indicate that energy consumers benefit from greater load payment reductions, but non-wind generators suffer due to inefficient operation of committed units. Comparing the system-wide variable cost reductions for these two cases, there is a $430M-$335M = $95M annual benefit to be gained from using wind energy forecasts for day-ahead unit commitment.

Table 2.5 Annual Operating Cost Impacts for 2001 Wind and Load Profiles
(Wind generation not included for unit commitment)

	System-Wide	**NYISO**
Total variable cost reduction *(includes fuel cost, variable O&M, start-up costs, and emission payments)*	$ 335M	$ 225M
Total variable cost reduction per MW-hour of wind generation	$38 / MWh	$25 / MWh
Wind revenue	$ 305M	$ 305M
Non-wind generator revenue reductions	$ 960M	$ 600M
Load payment reductions *(calculated as product of hourly load and the corresponding locational spot price)*	$ 720M	$ 455M

Any economic incentives that may be offered to wind generators should be designed to encourage use of state-of-the-art forecasting and active participation in the day-ahead power market.

2.3.7 Energy Displacement and Emission Reductions

Energy produced by wind generators will displace energy that would have been provided by other generators. Considering wind and load profiles for years 2001 and 2002, 65% of the energy displaced by wind generation would come from natural gas, 15% from coal, 10% from oil, and 10% from imports. As with the economic impacts discussed above, the unit commitment process affects the relative proportions of energy displaced, but the general trend is the same regardless of how wind generation is treated in the unit commitment process.

By displacing energy from fossil-fired generators, wind generation causes reductions in emissions from those generators. Based on wind and load profiles for years 2001 and 2002, annual NOx emissions would be reduced by 6,400 tons and SOx emissions would be reduced by 12,000 tons.

2.3.8 Transmission Congestion

Because most of the wind generation is located in upstate New York, transmission flows increase from upstate to downstate with the addition of wind generation. Figure 2.4 shows a time-duration curve of the UPNY-SENY (upstate New York to Southeast New York) interface flow for year 2008, with and without wind generation per the study scenario. Without wind generation, interface flow is at its limit for approximately 1100 hours. Wind generation increases the number of hours at limit to 1300. Most of the time, the interface is not limited and increased flows due to wind generation are accommodated.

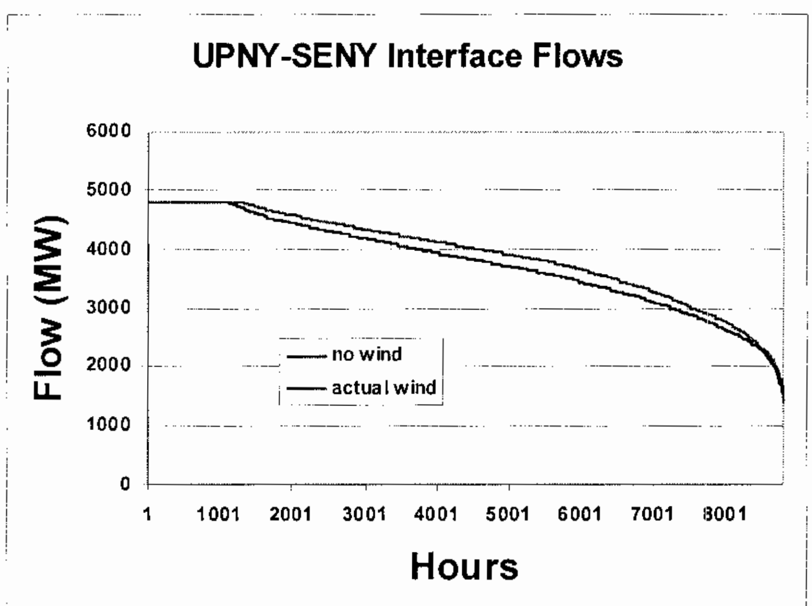

Figure 2.4 Duration Curve of Hourly Flows on UPNY-SENY Interface

2.4 Impact on System Reliability

2.4.1 Effective Capacity of Wind Generators

The effective capacity of wind generation in the study scenario was quantified using rigorous loss-of-load probability (LOLP) calculations with the Multi-Area Reliability Simulation (MARS) program. The results show that the effective capacities, UCAP, of the inland wind sites in New York are about 10% of their rated capacities, even though their energy capacity factors are on the order of 30%. This is due to both the seasonal and daily patterns of the wind generation being largely "out-of-phase" with NYISO load patterns. The offshore wind generation site near Long Island exhibits both annual and peak period effective capacities on the order of 40% - nearly equal to their energy capacity factors. The higher effective capacity is due to the daily wind patterns peaking several hours earlier in the day than the rest of the inland wind sites and therefore being much more in line with the load demand.

An approximate methodology for calculating effective capacity, UCAP, of wind generation was demonstrated. A wind generator's effective capacity can be estimated from its energy capacity factor during a four-hour peak load period (1:00 pm to 5:00 pm) in the summer months. This method produces results in close agreement with the full LOLP analytical methodology.

2.4.2 System Stability

The transient stability behavior of wind generation, particularly vector controlled WTGs, is significantly different from that of conventional synchronous generation. The net result of this behavior difference is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation.

It is recommended that New York State require all new wind farms to include voltage regulation and low voltage ride through (LVRT) features. Voltage regulation improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances. Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. However, it is recommended that NYS adopt the emerging LVRT specification (15% voltage at the point of interconnection for 625 milliseconds), consistent with the recent FERC NOPR on wind generation interconnection requirements.

2.5 Conclusions

Based on the results of this study, it is expected that the NYSBPS can reliably accommodate at least 10% penetration, 3,300 MW, of wind generation with only minor adjustments to its existing planning, operation, and reliability practices. This conclusion is subject to several assumptions incorporated in the development of the study scenario:

- Individual wind farms installed in NY State would require approval per the existing NYISO procedures, including SRIS.
- Ratings of wind farms would need to be within the capacity of local transmission facilities, or subject to local constraints.
- Wind farms would include state-of-the-art technology, with reactive power, voltage regulation, and LVRT capabilities consistent with the recommendations in this report.

3 Forecast Accuracy

3.1 Variability and Predictability

Reliable and economic operation of power systems requires good information about the present and expected future condition of the system. It is in this context that a brief examination of variability and predictability is warranted.

The variability of load on a seasonal and diurnal (daily) basis is mostly known and understood. All aspects of power system planning and operations are geared towards handling these variations. Load forecasts are used in three of the four time frames shown in Figure 1.2: resource planning (years ahead), unit commitment and scheduling (day-ahead), and load following (hour-ahead to 5 minute economic dispatch). Of course, perfect prescience is impossible, and the power system relies on various operating strategies to maintain the resilience necessary to provide reliable service subject to the inevitable inaccuracies in forecasts.

Variation in load is expected and can be predicted to a reasonable level of accuracy. The same is true for wind generation and other forms of non-dispatchable generation. Unlike dispatchable central station generation, most renewable resources, including wind, will produce power when conditions external to the power system (i.e., wind speed, insolation, rain run-off, etc.) dictate. It is the characteristics of these externalities that dictate both the variability and predictability of the resources. Figure 3.1 helps illustrate the important distinction between variability and predictability. In this figure, a range of non-dispatchable resources is placed to illustrate their relative variability and predictability. Non-dispatchable resources that rely on a steady supply of fuel or input energy, or which require a steady process, are both predictable and invariant. Digester type biomass and geothermal plants are good examples of this type of non-dispatchable resource. Tidal power is an example of a perfectly predictable but variable resource. The exact power production of a tidal plant can be predicted arbitrarily far in advance, but the four relative maxima and minima of power production per day mean that the resource is quite variable. The diurnal cycling of solar power means that it is highly predictable in the sense of being unavailable at night, but still subject to the weather related uncertainties of sunlight during the day. Wind will exhibit broadly predictable variation with season and daily cycling, but relative to the other resources in the figure will tend to show more variability that is somewhat less predictable that the other resources in the figure.

In broad terms, system operation relies on committable and dispatchable generation to meet the uncertain variations in the system. Non-dispatchable variable resources, such as wind generation, add to the inherent load variations and expand the duty on the dispatchable generation in the system. The balance of this section is focused on examination of the predictability of load and wind variability, and the implications for system operations. The actual impact of that variability on NYSBPS will be examined further in subsequent sections.

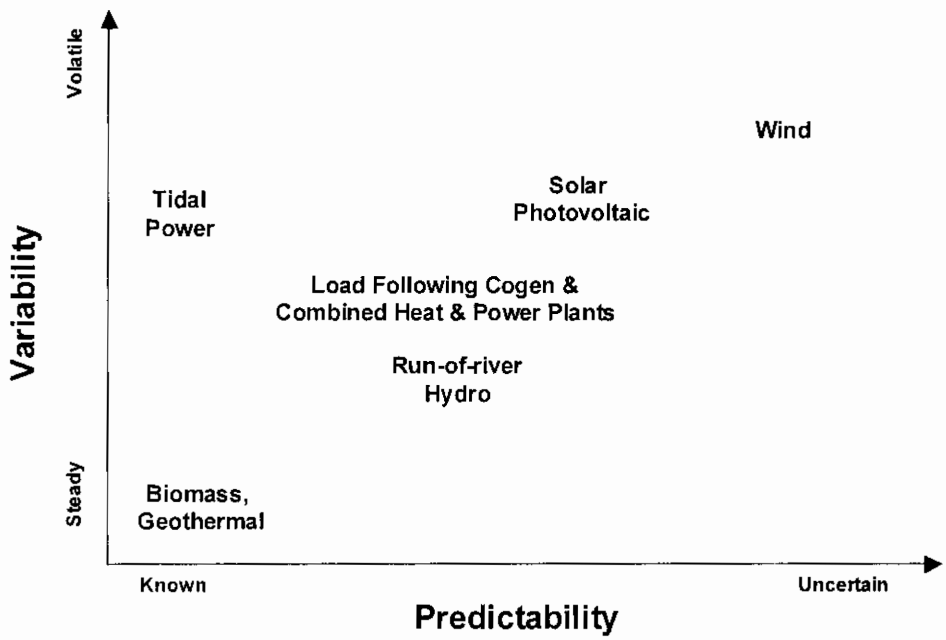

Figure 3.1 Variability and Predictability of Non-dispatchable Generating Resources.

3.2 Day-Ahead Forecasting

Reliable and economic operation of power systems requires good information about the present and expected future condition of the system. Day-ahead forecasting plays a crucial role in system operations, enabling the system to be positioned for secure and economic operation the following day. Forecasting is one of the key mechanisms by which the system operator reduces the degree of uncertainty in events and conditions for which the system must be prepared.

3.2.1 Day-Ahead Load Forecasting

Day-ahead load forecasting is based on a combination of long-term historical trends, recent weather and load history, and weather forecasts. Prior to November 1, 2001, the NYISO forecasting process used the larger of zonal load forecasts submitted by the load serving entities (LSEs) and the NYISO forecast, which resulted in a conservative or "biased" New York Control

Area load forecast. (i.e., the forecast load was consistently greater than actual load). After this date, the NYISO modified its day-ahead load forecasting process to an "unbiased" methodology

3.2.2 Day-Ahead Wind Forecasting

Wind forecasting is also based on history and weather forecasts. The historical aspects relate the specific behavior (i.e., power production) of a specific site to the broader predictions from meteorology. The forecasting data presented in this section is based on state-of-the-art techniques applied to each individual wind farm in the study scenario. The forecast data is based on the actual regional weather conditions, which were also a major factor in the corresponding system loads at the time. The report "Overview of Wind Energy Generation Forecasting"[ii] by AWS TrueWind provides a more complete discussion of the method and source of wind forecast data used in the analysis presented in this section.

The accuracy of wind forecasting is a function of the method used and the completeness of the site-specific power production history. Methods for quantifying the accuracy of wind forecasts vary. One commonly used metric of forecast accuracy is the "mean absolute error," or MAE. The MAE is the average of the absolute value of the difference between predicted power output and actual power output and is expressed as a percent of installed nameplate rating. Figure 3.2 shows MAE trends for a single wind farm for present state-of-the-art forecasting methods. Since the MAE is expressed on the percent of installed nameplate rating, the error expressed as a percent of actual power (or energy) produced is generally substantially higher. Unsurprisingly, the trend is that the farther in the future, the higher the error. These methods can achieve accuracies on the order of 13% to 21% MAE for day-ahead forecasting, by individual wind farm,.[iii] The MAE figures include the reality that individual hours can have very substantial errors, especially those associated with errors in anticipating the timing of significant changes in weather patterns. For example, the being off by a few hours in the prediction of the time when a weather front will pass a specific wind farm can result in large errors for the hours involved. Centralized, or at least coordinated, forecasting reduces these effects by providing a clearer regional picture of wind patterns and trends than can be achieved with only localized forecasting.

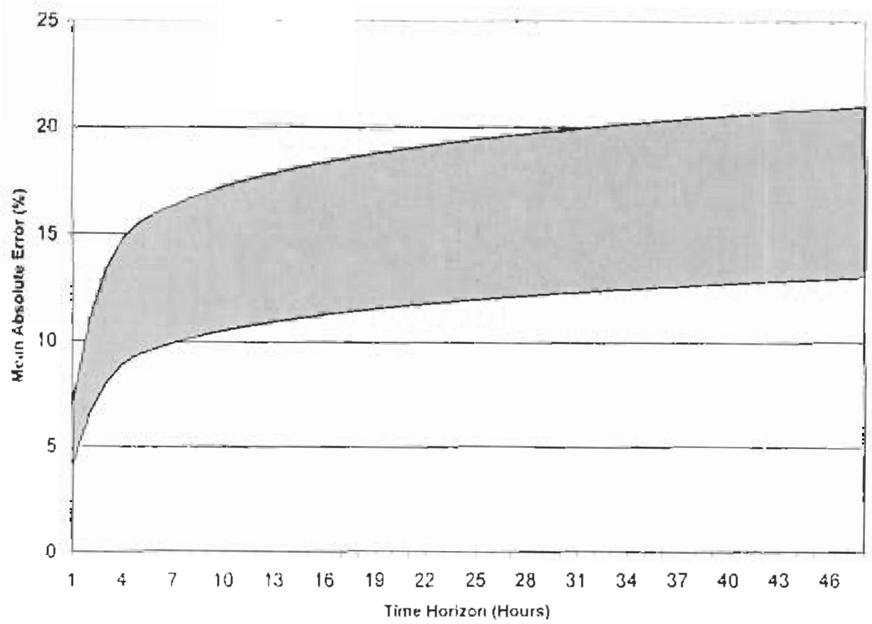

Figure 3.2 Wind Forecasting Accuracy for an individual Wind Farm

3.2.3 Discussion of Timing

As noted above, the daily rhythm of system operation includes day-ahead forecasting. It is useful to examine what "day-ahead" means in the context of forecasting and operations planning.

Figure 3.3 shows the sequence of key events related to day-ahead forecasting and unit commitment. The figure shows the day prior to the actual day of operation (which starts at 0:00 hr). In the upper left portion of the figure, the day-ahead load forecast is input to the day-ahead security constrained unit commitment (SCUC) software at NYISO at 5:00 am.[iv]

For wind forecasting, a primary input is the regional scale physics-based atmospheric model. Typically, these weather forecasts are executed at a national forecast center such as the National Center for Environmental Prediction (NCEP) operated by the U.S. National Weather Service. This forecast is used for a broad range of applications (transportation, defense, etc.) of which power systems operations is a subset. The weather forecast is used in the NYISO load forecast, and is used by the NYISO for security posturing of the system for extreme weather conditions[v]. The weather forecast is issued at 12-hour intervals. For NYS, the weather forecast available at midnight GMT (29 hours before the day of operation) provides a window of ten hours for processing in wind forecasting software. The resultant day-ahead wind forecast would be delivered to the day-ahead SCUC software also at 5:00 am and covers the entire next day. Thus, at 5:00 am, the day-ahead forecast actually ranges from 19 hours ahead (the midnight to 1:00 am hour) up to 42 hours ahead (the 11:00 pm to midnight hour). Fortunately, with state-of-the-art wind forecasting, the accuracy of the forecast for the last hour is nearly as good as for the first hour.

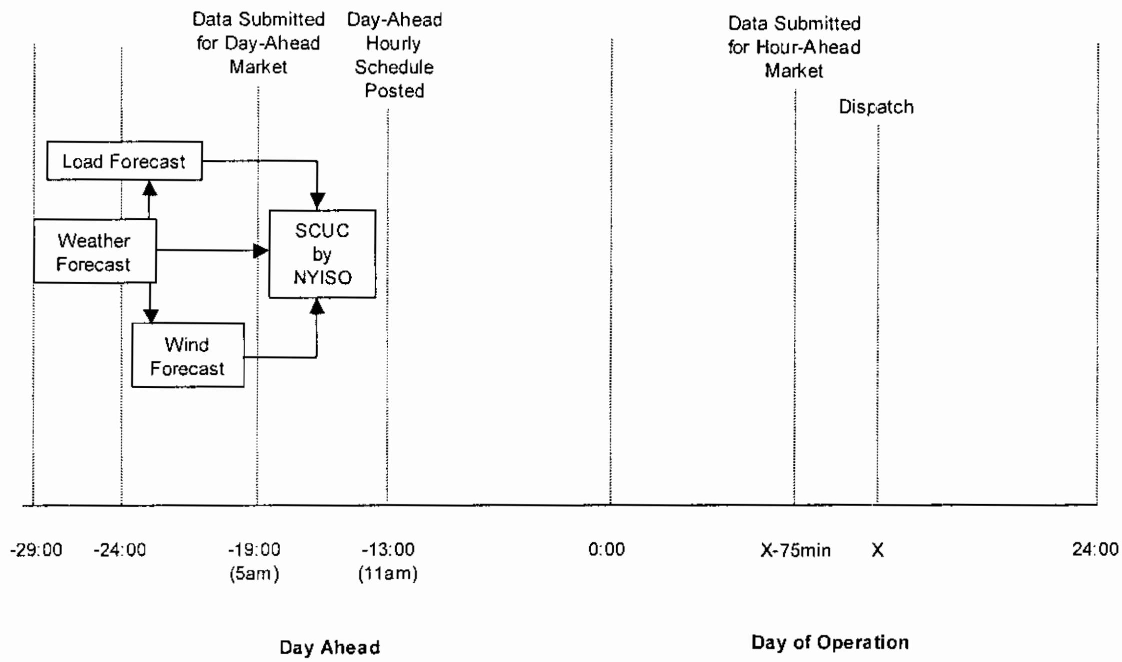

Figure 3.3. Timeline for Day-Ahead Forecasting

3.3 Day-Ahead Forecasting Error Analysis

Errors in load forecasting and wind generation forecasting are inseparable from a system-operation perspective. Errors in wind forecast are not particularly meaningful in isolation, but rather are relevant in so far as they impact decisions and reliability when compounded with errors in load forecasting. Thus, from a practical perspective, since the power system is designed and operated with the recognition that load behavior is not perfectly predictable, this analysis is aimed at examining the impact of the incremental uncertainties introduced by wind generation. In the first subsection below, detailed results of error analysis for a single month of system operation will be examined. Examination of a single month of operation has the benefit of providing good detail and yet a significant statistical sampling. A one-month sample makes it easier to observe daily and weekly trends. Analysis was performed on multiple months across multiple years, the results of which confirm the observations on this sample month. Summary of those results are presented in the next subsection. The impact of the change in NYS load forecasting methodology is addressed there.

3.3.1 Day-Ahead Forecasting Error Analysis for January 2001

The behavior shown in Figure 3.4 is illustrative of the relationship between load and wind generation. The sign convention is such that wind is treated as a load modifier; therefore load minus wind represents the net load that must be served by generation other than wind. The data plotted is for the entire state, including all the wind generation sites in the study scenario. The six traces, in the order listed in the legend, are as follows:

2001 Actual Load – the hourly load served statewide during January 2001.

2001 Load Forecast – the day-ahead load forecast provided to the NYISO SCUC.

Actual Total – The actual load minus the wind power that would have been produced at that time for the study wind generation scenario.

Forecast Total - The forecast load minus the forecast wind power.

Forecast Wind – The wind power that would have been forecast a day-ahead at that time for the study wind generation scenario during January 2001.

Actual Wind – The wind power that would have been produced at that time for the study wind generation scenario.

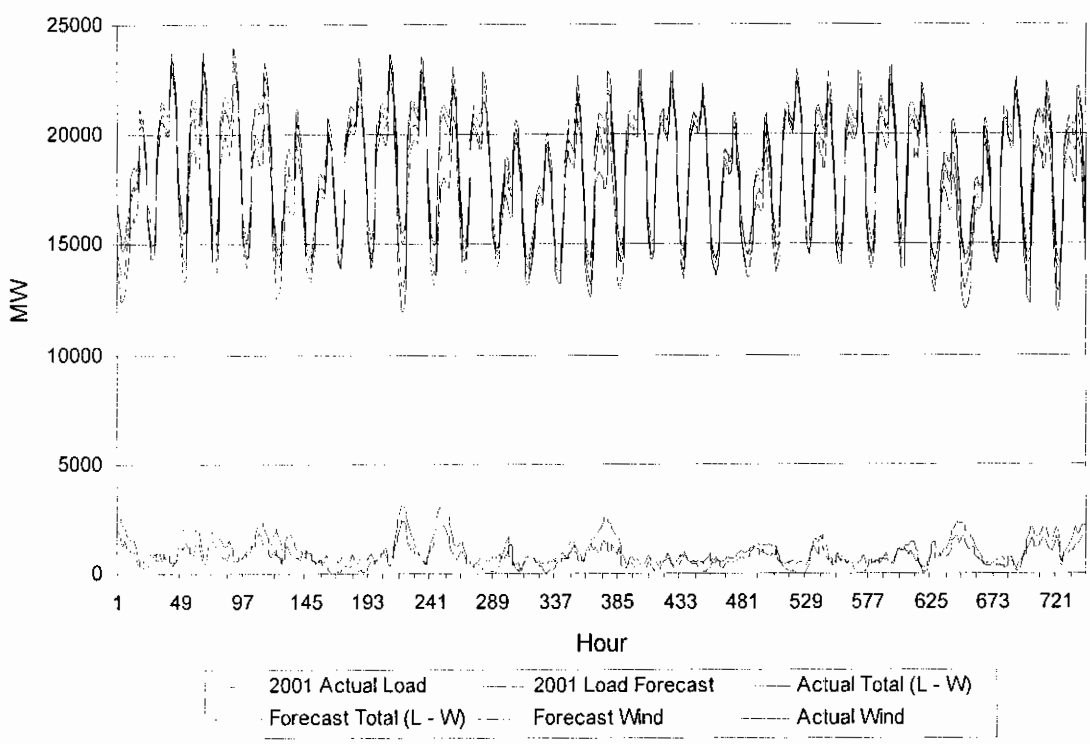

Figure 3.4 Day-Ahead Forecasts vs. Actual Hourly for January 2001

The figure shows the diurnal cycling and differences between weekdays and weekends. Since this is January, the peak daily load occurs in the evening. Overall, the figure shows that in broad-terms, the forecast behavior of the system tracks the actual behavior quite well.

The differences between forecast and actual behavior, the forecast error, can be seen more clearly in Figure 3.5. The three traces in the figure show the following, respectively:

Load Error - The difference between the forecast load and actual load.

Wind Error – The difference between the actual wind and forecast wind.

Total Error – The difference between the forecast total and the actual total.

Understanding the sign convention here is very important. The sign of the error for each trace is selected such that a positive error means the net requirement for generation resources (other than wind) is less than predicted. Thus, a positive error means that units will be over-committed and over-scheduled. Conversely, a negative error means that additional generation will be required beyond that which is predicted. In general, errors in both directions have economic consequences, but the reliability implications of under predicting (negative error) are somewhat more serious than for over-prediction.

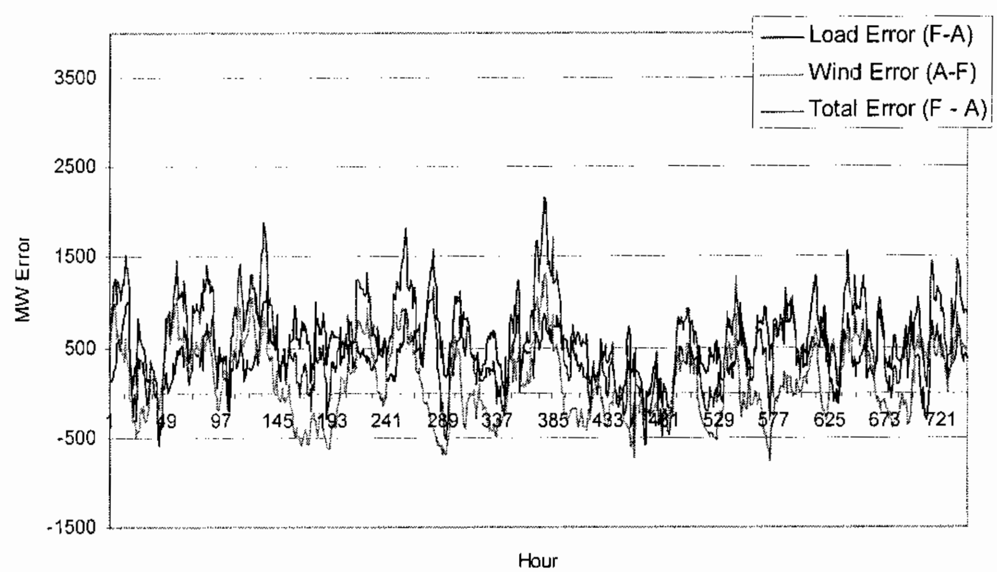

Figure 3.5 Day-Ahead Forecast Errors for January 2001

Overall, the total error (i.e., the error with wind generation present and included in the forecast) is slightly greater than the forecast error without wind. As expected, the total error may be less or greater than the load alone error, depending on the sign of the wind error relative to the load error.

Figure 3.6 shows the hourly duration curve for the three errors. Note that there are 744 hours in January. In this figure, it is easier to see that the load and wind error are not simply additive, (this is, the sum of the blue load error trace and the green wind error trace does not equal the red total trace). Rather they depend on the coincidence or lack thereof, in the errors. The zero crossings of the three traces define the transition from negative error (to the left of the zero crossing) and positive error (to the right).

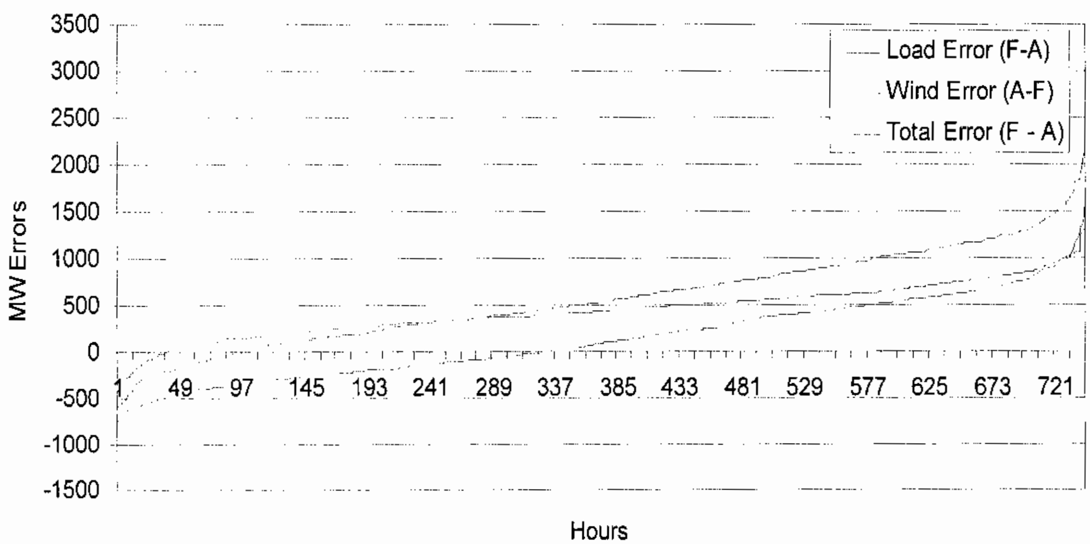

Figure 3.6 Day-Ahead Error Duration Curve for January 2001

The statistics on distribution of errors across the month are summarized in Table 3.1. The entries in the table, for each of the three quantities (columns) are as follows:

Hours Negative – The count of hours for which the forecast is low (i.e., more generation will be needed than predicted).

Hours Positive - The count of hours for which the forecast is high. (i.e., less generation will be needed than predicted).

Negative Energy Error – The total energy requirement (in MWh) under predicted (the area under zero and above the forecast error curve in Figure 3.6).

Positive Energy Error - The total energy requirement (in MWh) over predicted (the area above zero and below the forecast error curve in Figure 3.6).

Net Energy Error – The total error in energy requirement predicted (the integral of the forecast error).

Worst Negative Error – The extreme or worst hour under prediction (the leftmost point in the duration curve).

Worst Positive Error – The extreme or worst hour over prediction (the rightmost point in the duration curve).

Peak – The maximum actual load or wind generation for the month.

Min – The minimum actual load or wind generation for the month.

Energy – The total actual load or wind generation for the month.

Negative Energy Error – The total energy requirement under predicted expressed as a percentage of the total load energy served. (Entries for all three columns are normalized to the load energy in the first column).

Positive Energy Error – The total energy requirement over predicted expressed as a percentage of the total load energy served. (Entries for all three columns are normalized to the load energy in the first column).

MAE – Mean absolute error of the forecasts, expressed in MW.

STD on Error - The standard deviation (sigma, σ) of the forecast errors, in MW.

MAE % – Mean absolute error of the forecasts, expressed in percent of the installed MW of wind generation (3300 MW).

Table 3.1. Forecast Error Statistics for January 2001

2001 Jan Day Ahead	Load	Wind	Load - Wind
Hours Negative	39	329	94
Hours Positive	705	415	650
Negative Energy Error (MWh)	-6,058	-85,645	-18,655
Positive Energy Error(MWh)	332,772	180,573	440,297
Net Energy Error (MWh)	326,714	94,928	421,642
Worst Negative Error (MW)	-433	-753	-581
Worst Positive Error (MW)	1,581	1,310	2,174
Peak (MW)	23,720	3,149	23,273
Min (MW)	13,754	3	11,937
Energy (MWh)	13,719,259	723,591	12,995,668
Negative Energy Error(% of LE)	-0.04	-0.62	-0.14
Positive Energy Error(% of LE)	2.43	1.32	3.21
MAE (MW)	455	358	617
STD on Error (MW)	277	416	491
MAE (% of Rating Wind)	13.80	10.84	18.69

This table shows that errors in day-ahead load forecasting for this month result in over prediction of load energy of about two and half percent of the total load energy served. The biased load forecasting results in almost nil (about 6 GWhr) under prediction of load energy. The addition of wind increases the net over prediction by about 0.8%, or 100 GWhr. The under prediction increases about 0.1% (12 GWhr) due to wind forecast errors. These changes in errors are not expected to have any reliability impacts. The errors have the potential to increase economic inefficiencies due to suboptimal commitment. This is examined in Section 4, *Hourly Production Simulation Analysis*.

The table shows system-wide MAE for the month of 10.84%. This reflects the aggregate benefits of forecasting for multiple plants. The MAEs for the individual wind farms for the month are shown in Figure 3.7. These range from about 14 to 19%, and are consistent with state-of-the-art forecasting for individual plants.

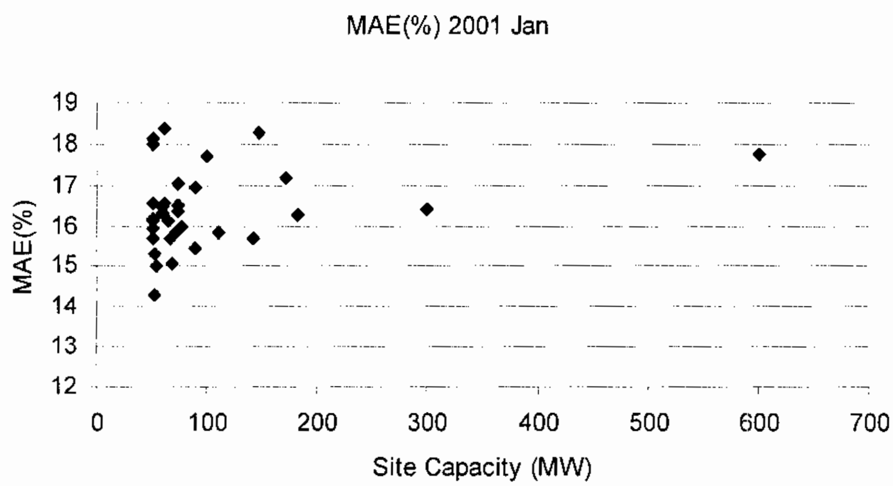

Figure 3.7 Mean Absolute Error (MAE) for Individual Wind Farms Forecasts - January 2001

3.3.2 Day-Ahead Forecasting Error Analysis for Multiple Months

Similar analysis was conducted on the following 10 months, for which data was available:

- April, August, October 2001
- January, April, August, October 2002
- January, April, August 2003

Detailed results for each month are included in Appendix B. The next sequence of figures shows results from the total eleven months of analyzed data. Figure 3.8 shows the standard deviation for the eleven months, plotted against the peak load for that month.

The standard deviation, usually denoted sigma (σ), provides a good index of expected behavior of variable phenomena. In a normal distribution 68% of events are within $\pm 1\sigma$, 95% of events are within $\pm 2\sigma$, and 99.7% of events are within $\pm 3\sigma$.

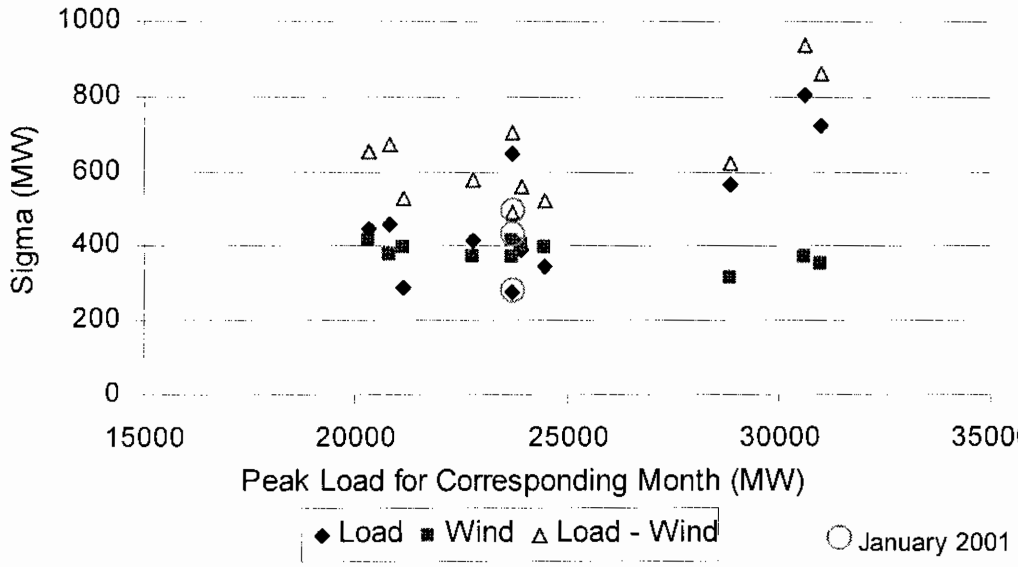

Figure 3.8 Standard Deviation of Day Ahead Forecast Errors

This figure shows that the total forecasting error (load – wind) is somewhat higher than the forecasting error due to load alone. For example in peak load months (points on the right hand of the plot), the forecast error increases from around 750-800 MW to about 850-950 MW. During lightest load months (left hand side) the forecast error increases from about 450 MW to 650 MW.

The sigmas for January 2001 are circled in the figure. The sigma for load forecast error was the lowest of the eleven moths, and the increase in sigma with the addition of wind (from 277 to 491 MW) was one of the largest. This is a confirmation that more detailed examination of January 2001 is conservative.

Since the operational implications of a positive error (excess generation will be scheduled) are different from those of negative error (less generation will be scheduled), it is useful to examine the two faces of error separately. Figure 3.9 shows the count of hours for which each of the forecasts errors is positive (these months have either 720 or 744 hours). Figure 3.10 shows the corresponding count of negative error hours. The load errors show a noticeable shift towards a more balanced split between negative and positive hours starting around April 2002. This appears to correspond to the NYISO moving to unbiased load forecasting in late 2001, though the effect becomes obvious somewhat later (i.e., April 2002 versus Jan 2002).

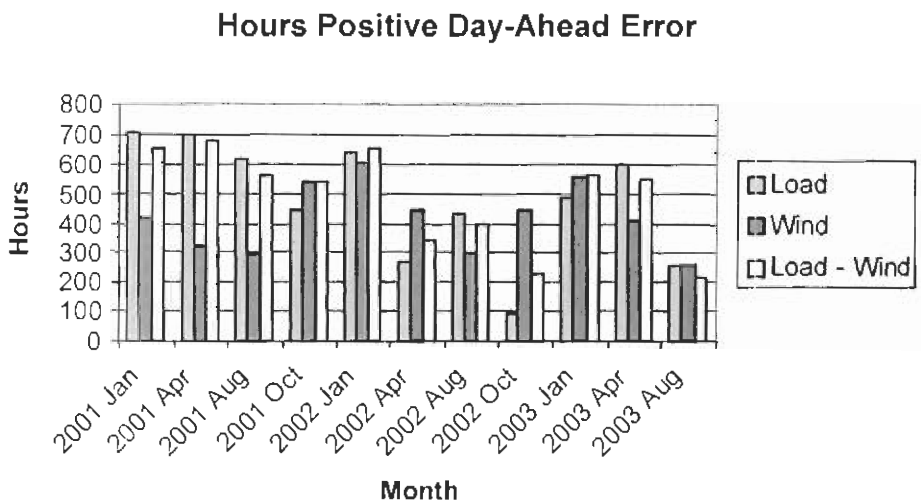

Figure 3.9 Day-Ahead Positive Forecast Error Frequency

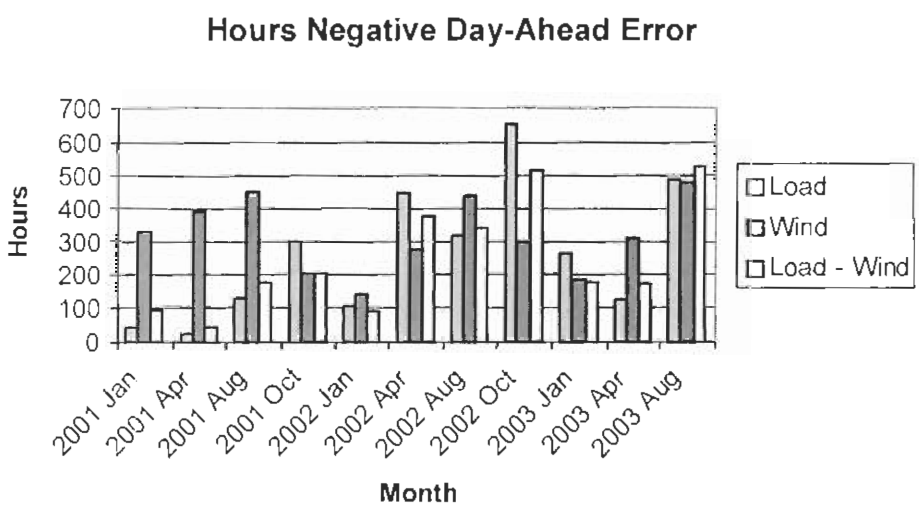

Figure 3.10 Day-Ahead Negative Forecast Error Frequency

The total energy involved in the forecast error is a means of quantifying the operational impact on the system. Figure 3.11 and Figure 3.12 show the total monthly energy associated with day-ahead forecast errors. Again, the shift in bias starting in April 2002 for the load forecast is quite apparent. Finally, the annual statistics corresponding to data in Table 3.1 are shown for each of the three years of available data in Table 3.2, Table 3.3 and Table 3.4. Again, the shift to unbiased load forecasting between 2001 and the later years is apparent in the data.

The system-wide MAE on the wind forecast varies between 10.17% and 10.80% across the three years. Again, these are consistent with state-of-the-art forecasting, which would produce MAE between 13% and 21% on an individual plant basis.

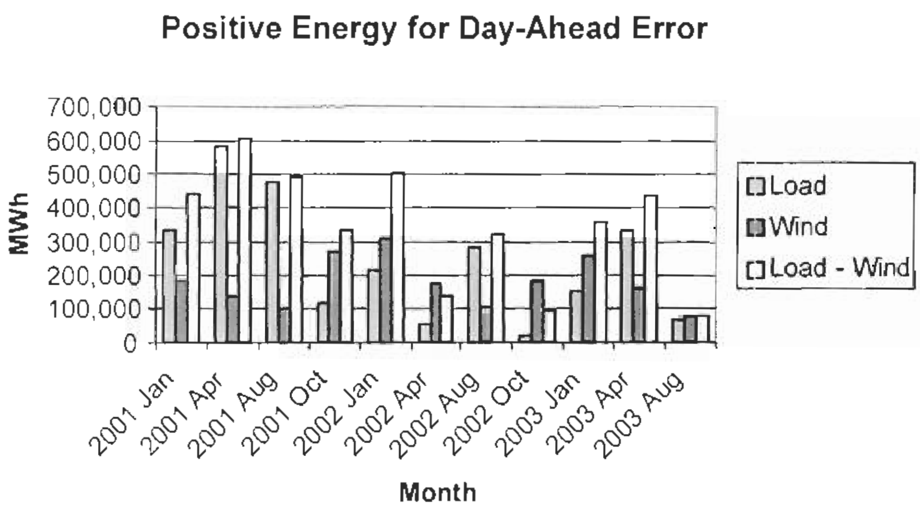

Figure 3.11 Positive Energy Error for Day-Ahead Forecasts

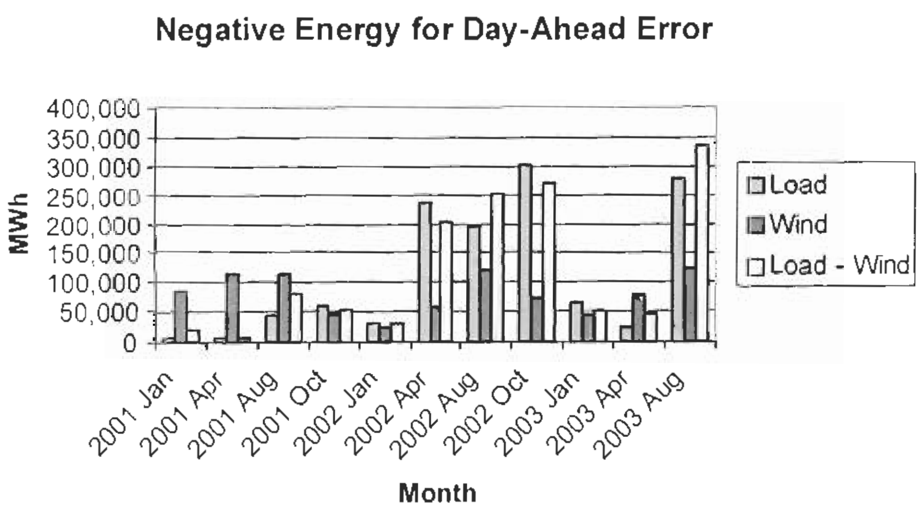

Figure 3.12 Negative Energy Error for Day-Ahead Forecasts

Table 3.2 2001 Day-Ahead Forecast Error Statistics (4 months)

2001 Day Ahead 4 Months	Load	Wind	Load - Wind
Hours Negative	490	1,380	516
Hours Positive	2,462	1,572	2,436
Negative Energy Error (MWh)	-115,714	-360,297	-162,788
Positive Energy Error(MWh)	1,505,209	681,498	1,873,484
Net Energy Error (MWh)	1,389,495	321,201	1,710,696
Worst Negative Error (MW)	-1,052	-770	-1,446
Worst Positive Error (MW)	3,569	1,310	3,485
Peak (MW)	30,982	3,149	30,596
Min (MW)	11,600	0	8,912
Energy (MWh)	53,619,075	2,917,948	50,701,127
Negative Energy Error(% of LE)	-0.22	-0.67	-0.30
Positive Energy Error(% of LE)	2.81	1.27	3.49
MAE (MW)	549	353	690
STD on Error (MW)	539	414	668
MAE (% of Rating Wind)	16.64	10.69	20.90

Table 3.3 2002 Day-Ahead Forecast Error Statistics (4 months)

2002 Day Ahead 4 Months	Load	Wind	Load - Wind
Hours Negative	1,525	1,157	1,324
Hours Positive	1,427	1,795	1,629
Negative Energy Error (MWh)	-765,532	-276,466	-751,578
Positive Energy Error(MWh)	577,488	775,975	1,063,043
Net Energy Error (MWh)	-188,044	499,509	311,465
Worst Negative Error (MW)	-3,398	-728	-3,654
Worst Positive Error (MW)	3,755	1,215	4,436
Peak (MW)	30,596	3,227	30,476
Min (MW)	11,705	0	9,690
Energy (MWh)	53,784,416	3,116,211	50,668,205
Negative Energy Error(% of LE)	-1.42	-0.51	-1.40
Positive Energy Error(% of LE)	1.07	1.44	1.98
MAE (MW)	455	357	615
STD on Error (MW)	644	405	785
MAE (% of Rating Wind)	13.79	10.80	18.63

Table 3.4 2003 Day-Ahead Forecast Error Statistics (3 Months)

2003 Day Ahead 3 Months	Load	Wind	Load - Wind
Hours Negative	878	979	878
Hours Positive	1,330	1,229	1,330
Negative Energy Error (MWh)	-363,028	-246,180	-434,364
Positive Energy Error(MWh)	552,405	495,155	872,717
Net Energy Error (MWh)	189,377	248,975	438,352
Worst Negative Error (MW)	-2,327	-842	-2,331
Worst Positive Error (MW)	2,030	1,332	2,415
Peak (MW)	30,596	3,215	30,476
Min (MW)	11,705	0	9,690
Energy (MWh)	41,019,162	2,354,595	38,664,567
Negative Energy Error(% of LE)	-0.89	-0.60	-1.12
Positive Energy Error(% of LE)	1.35	1.21	2.26
MAE (MW)	415	336	592
STD on Error (MW)	552	392	725
MAE (% of Rating Wind)	12.56	10.17	17.94

There is a significant monthly variance in the cumulative energy associated with forecast error. A comparison of the monthly errors, with and without wind, shows remarkably similar results. Most months are slightly worse, while a few are slightly better. Figure 3.13 shows the distribution of energy errors as a percent of the total energy served for the month. In most months, the negative energy error is about 2% or less of the total energy delivered, with wind forecast errors having little impact. The worse negative error occurs for October 2002, with no wind. During months with lower peak loading, the positive error tends to increase by about 0.5% to 2%; during peak load months, the impact is a fraction of one percent. The highest positive error is for April 2001, before NYISO changed to unbiased load forecasts. After changing to unbiased forecasting, the worst positive error is 2.8% without wind, and 3.7% with wind, an increase of 0.9%.

From an operational reliability perspective, the incremental forecast error associated with wind generation is within the range of uncertainty currently handled successfully in NYISO operations.

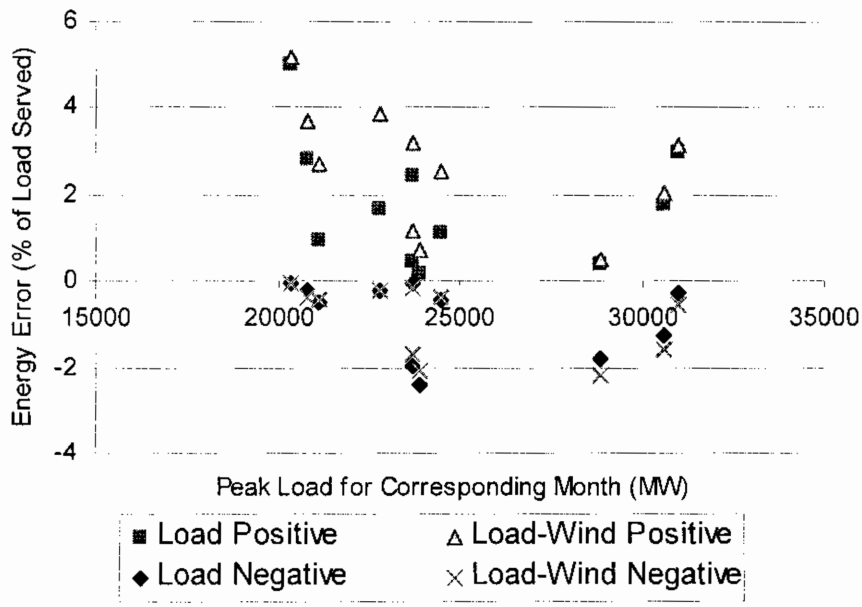

Figure 3.13 Distribution of Forecast Energy Errors

3.4 Hour-Ahead Forecasting

During daily operation, the NYISO updates its load forecast on an hourly basis. This forecast is used as input to the hour-ahead market, 75 minutes before the subject hour starts, as shown in Figure 3.3. The hour-ahead market provides an opportunity to update and refine the wind forecast in parallel with the load forecast. NYISO also performs a five-minute ahead load forecast, which is included in the five-minute economic dispatch. Operationally, the hour ahead market and intrahour economic dispatch provide a more limited range of options for system operators. Specifically, the ability of system operators to commit generation in this time frame is very limited. Consequently, the need for accuracy in the hour ahead forecast is greater.

Hour-ahead wind forecasting, as one would expect, is significantly more accurate than day-ahead and longer-term forecasts. Relatively simple (persistence) forecasting typically produces MAE values of about 5% of plant rating[vi] looking a single hour ahead. For operations, "hour-ahead" actually means 2¼ hour-ahead, since the forecast must be performed and fed to system operations. In this section, the relative accuracy of these "hour-ahead" and day-ahead wind forecasting is examined. As in the previous section, the month of January 2001 is presented in detail.

Figure 3.14 shows the following three traces:

Forecast DA Wind – The wind power that would have been forecast a day-ahead at that time for the study wind generation scenario.

Forecast HA Wind – The wind power that would have been forecast an hour-ahead at that time for the study wind generation scenario.

Actual Wind – The wind power that would have been produced at that time for the study wind generation scenario.

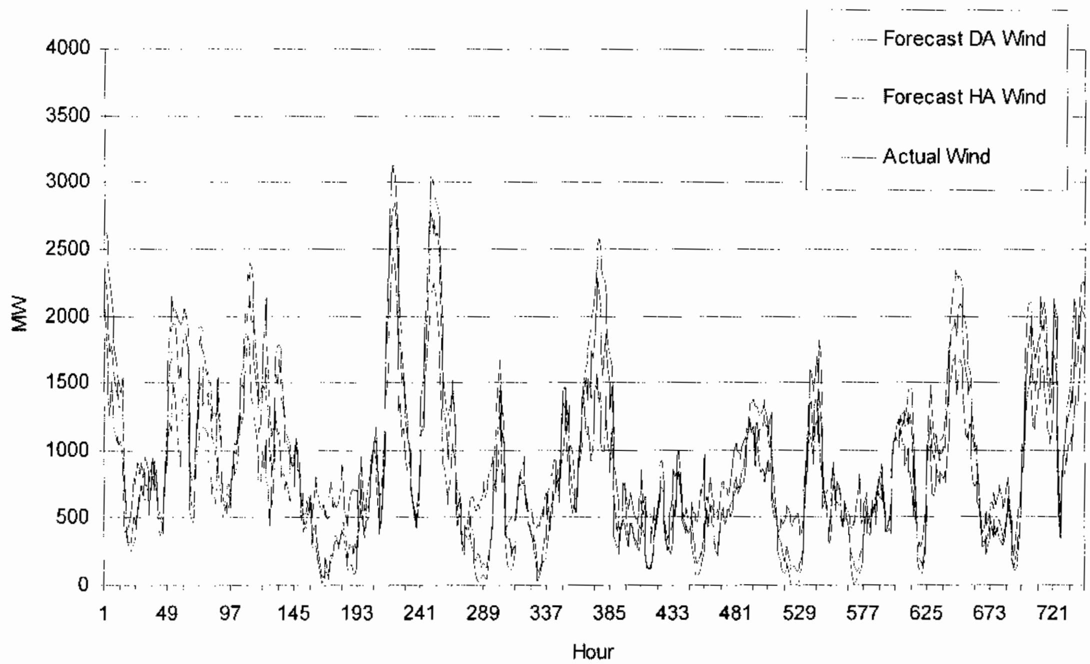

Figure 3.14. Day-Ahead and Hour-Ahead Wind Forecast and Actual Wind for January 2001

Figure 3.15 shows the error for the two forecasts, and Figure 3.16 shows the error duration curves for the same period. These figures show that the forecast accuracy improves considerably as the forecast horizon draws closer. The improvement can be observed quantitatively in the statistics for this month of data, which are shown in Table 3.5. Most of the hour-ahead error metrics summarized in the table drop by about 50% to 60% of their day-ahead values. For example, the mean absolute error (MAE) drops from 358 MW (10.84% of total wind rating) to 135 MW (4.10% of rating) - a 62% improvement. The system-wide hour-ahead MAE for the wind forecast ranges between 4.10% and 4.23%, which is consistent with the expectation of about 8-12% MAE on an individual plant basis (again, recalling that this is actually 2¼ hours ahead).

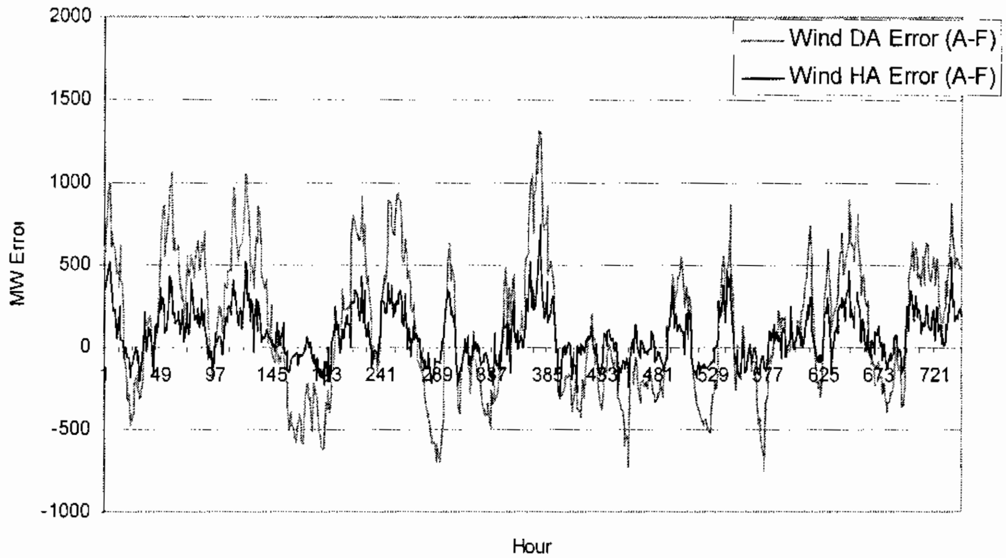

Figure 3.15 Day-Ahead and Hour-Ahead Wind Forecast Error for January 2001

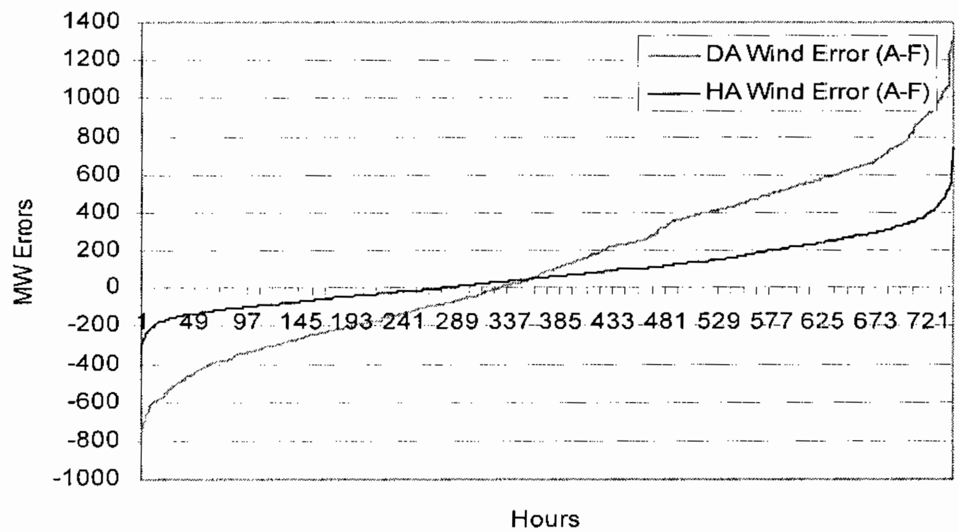

Figure 3.16 Day-Ahead and Hour-Ahead Wind Forecast Error Duration for January 2001

Table 3.5 Day-Ahead vs Hour-Ahead Wind Forecast Error Statistics for January 2001

2001 Jan Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	329	280
Hours Positive	415	464
Negative Energy Error (MWh)	-85,645	-23,098
Positive Energy Error(MWh)	180,573	77,491
Net Energy Error (MWh)	94,928	54,393
Worst Negative Error (MW)	-753	-295
Worst Positive Error (MW)	1,310	747
Peak (MW)	3,149	3,149
Energy (MWh)	723,591	723,591
Negative Energy Error(% of LE)	-0.62	-0.17
Positive Energy Error(% of LE)	1.32	0.56
MAE (MW)	358	135
MAE (% of Rating Wind)	10.84	4.10

The same analysis was performed for the other ten months of available data, with similar results. See appendix B.2 for detailed results by month. Figure 3.17 shows a comparison of the standard deviation of the day-ahead and hour-ahead wind forecasts. This figure shows a relatively consistent improvement of 50% to 60% from day-ahead to hour-ahead wind forecasting, that has a slight negative correlation to peak load. This negative correlation is due to lower average wind powers during months of peak load (as discussed in Section 7, *Effective Capacity*). Comparisons of hour-ahead and day-ahead error statistics for the three years of available data are shown in Table 3.6, Table 3.7, and Table 3.8.

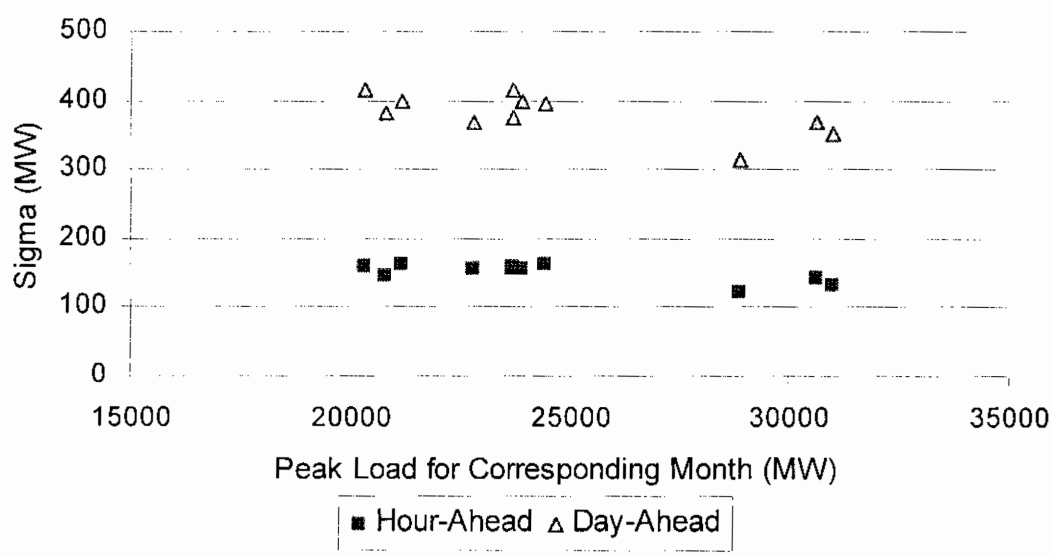

Figure 3.17 Day-Ahead vs Hour-Ahead Wind Forecast Error Sigma

Table 3.6 Statistics on Wind forecast Error for 2001

2001 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,773	3,123
Hours Positive	4,987	5,637
Negative Energy Error (MWh)	-915,144	-244,659
Positive Energy Error(MWh)	2,112,992	948,017
Net Energy Error (MWh)	1,197,848	703,357
Worst Negative Error (MW)	-770	-367
Worst Positive Error (MW)	1,310	747
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	8,897,766	8,897,766
Negative Energy Error(% of LE)	-0.58	-0.16
Positive Energy Error(% of LE)	1.35	0.61
MAE (MW)	346	136
STD on Error (MW)	403	157
MAE (% of Rating Wind)	10.48	4.13

Table 3.7 Statistics on Wind Forecast Error 2002

2002 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,263	2,684
Hours Positive	5,497	6,076
Negative Energy Error (MWh)	-757,377	-205,048
Positive Energy Error(MWh)	2,473,487	1,086,445
Net Energy Error (MWh)	1,716,110	881,398
Worst Negative Error (MW)	-798	-487
Worst Positive Error (MW)	1,266	676
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	9,873,862	9,873,862
Negative Energy Error(% of LE)	-0.48	-0.13
Positive Energy Error(% of LE)	1.56	0.68
MAE (MW)	369	147
STD on Error (MW)	407	158
MAE (% of Rating Wind)	11.18	4.47

Table 3.8 Statistics on Wind Forecast Error 2003

2003 Wind Error	DayAhead Wind	HourAhead Wind
Hours Negative	3,763	3,084
Hours Positive	4,997	5,676
Negative Energy Error (MWh)	-939,134	-249,494
Positive Energy Error(MWh)	2,101,866	966,351
Net Energy Error (MWh)	1,162,732	716,857
Worst Negative Error (MW)	-889	-425
Worst Positive Error (MW)	1,341	688
Peak (MW)	3,234	3,234
Min (MW)	0	0
Energy (MWh)	9,020,543	9,020,543
Negative Energy Error(% of LE)	-0.59	-0.16
Positive Energy Error(% of LE)	1.33	0.61
MAE (MW)	347	139
STD on Error (MW)	400	157
MAE (% of Rating Wind)	10.52	4.21

These three tables show that the levels of forecast error expected are fairly steady across the three years of data. The total energy involved in these hour ahead forecast errors is a fraction of a percent of the total load supplied in the NYSBPS. Over the three years of data, the hour-ahead negative energy error (i.e., over-prediction of wind power) ranged from 0.13% to 0.16% of total load energy served. The total hour-ahead positive energy error (i.e., under-prediction of wind power) ranged from 0.61% to 0.68% of total load energy served.

3.5 Centralized Versus Decentralized Forecasting

In both centralized and decentralized forecasting systems, forecasts will be made for individual wind projects. Furthermore, in both systems, the individual forecasts will be aggregated to regional and state totals, whether by the central provider or the ISO itself. Thus, both offer the benefit that forecast errors at one project will offset uncorrelated forecast errors at other projects, resulting in a smaller overall error for the entire system (as a fraction of the rated wind capacity).

The key difference between the two systems is that in a centralized system, a single forecasting entity would take responsibility for both generating the individual plant forecasts and aggregating them. This offers several potential benefits:

- A single entity will apply a consistent methodology and presumably achieve more consistent results across projects than a number of individual forecasting services. (On the other hand, if the entity uses an inferior method, forecasts for all plants would suffer.

Setting standards and providing incentives and disincentives to encourage the best possible forecasts can address this potential risk.)

- A single entity can more effectively identify approaching weather systems affecting all plants and warn the ISO of impending large shifts in wind generation; whereas individual forecasters might provide a number of different warnings at different times; which could produce confusion.
- A centralized entity can make use of data from each plant to improve the forecasts at other plants. For example, a change in output of one plant might signal a similar change in other plants downstream of the first. Individual forecasters would not have access to the data from other projects to make this possible.
- A centralized forecasting system allows for greater accountability. If the forecasts are not satisfactory, the ISO will know whom to hold responsible.
- A centralized system offers potentially large economies of scale, since many of the costs of forecasting for a given region are fixed.

3.6 Conclusions and Recommendations

3.6.1 Conclusions

Uncertainties introduced by errors in day-ahead forecasts for wind add slightly to those due to load forecasting, which are presently accommodated by system operations. The worst under-prediction of load, 2.4% of load energy served, occurs without wind generation. The worst over-prediction of load without wind generation is 2.8%, and 3.7% with wind generation.

Hour-ahead wind forecasts significantly reduce the uncertainties associated with the day-ahead forecasts. On a system-wide basis the wind forecast error (MAE and energy) is reduced by 50% to 60%.

Existing NYISO operating practices account for uncertainties in load forecast. The incremental uncertainties due to imperfect wind forecasts are not expected to impact the reliability of the NYSBPS.

These conclusions are based on the assumption of state-of-the-art wind forecasting, applied consistently to all wind resources in the state.

The operational impacts of these forecast uncertainties, and various methods to use forecasts in day-ahead operations, are further quantified in Section 4, *Hourly Production Simulation Analysis*.

3.6.2 Recommendations

The conclusion that uncertainties due to imperfect wind forecasts are not expected to impact the reliability of the NYSBPS is based the use of state-of-the-art forecasting. Development of statewide wind forecasting should be pursued.

Data collection from existing and new wind farms should proceed immediately, in order to provide input to, and increase the fidelity of, wind forecasts for when the system achieves higher levels of penetration.

Meteorological data collection and analysis from proposed and promising wind generation locations should proceed in order to aid and accelerate the development of high fidelity forecasting. Participation by NYS Transmission Owners, the NYISO and project developers and owners in recommended.

4 Hourly Production Simulation Analysis

4.1 Introduction

This section examines the impact of the addition of significant amounts of wind generation on the overall operation of the NYISO system. The commitment and dispatch of the system are examined both with and without the addition of wind generation and with varying assumptions on the forecast accuracy. Key issues include the economic impact of the wind turbines on the system operation, the impact on transmission congestion, minimum load issues, emissions and what generation is displaced by technology, fuel type and location. The wind energy is assumed to be a "price taker" and is bid into the system at zero. This section only examines the operational impact and does not attempt to examine the overall economics of wind turbine generation.

4.1.1 Description of Cases

The basic data used for the analysis was from the NYPSC's MAPS database used for their RPS analysis in early 2004. The fuel prices were updated to be consistent with their fall 2004 studies. The power flow representation was updated with data provided by the NYISO in order to be consistent with the steady state and dynamic analysis performed in Section 6, *Operational Impacts*. Historical load shapes were used for both 2001 and 2002 along with wind data for the corresponding years. The year 2008 was selected for the analysis to reflect future system conditions. Peak loads and energies were adjusted to the 2008 forecasts provided by the NYISO. A summary of the wind farms by zone is shown in Section 1, *Introduction*. The existing generation and loads in PJMISO and ISONE were also fully modeled with Canada and other, more remote regions modeled more simply. A number of operating scenarios were examined. The cases, and their abbreviations used later in the summaries, are shown in Table 4.1 below.

Table 4.1 Description of Cases

Case	Abr.
no wind	no
actual wind for commitment, schedule wind after hydro	act
no commitment credit for wind	nc
forecast wind for commitment, schedule wind after hydro	fc
actual wind for commitment, schedule wind before hydro	act-prio
forecast wind for commitment, schedule wind before hydro	fc-prio

The base case, "no," assumed no new wind generation. For both the 2001 and 2002 scenarios wind generation data was provided based on actual meteorological conditions as well as based on the conditions predicted on the day ahead. This was to simulate the impact of predicting the wind generation in order to bid into the day ahead market. The comparisons of the day ahead, hour ahead and actual wind schedules is discussed in Section 3, *Forecast Accuracy*.

In the first wind case, "act," it was assumed that the forecast was 100% accurate. That is, the schedule used for the commitment of the thermal generation assumed perfect foreknowledge of the wind generation. The hydro schedules, however, were based on the load shapes only and were not adjusted based on the wind schedules.

The second wind case, "nc," assumed that there was no day ahead forecast available for the wind. The commitment schedule for the thermal generation was exactly the same as in the base case with no wind. Only the dispatch was modified to reflect the real time wind generation.

The third wind case, "fc," used the day ahead schedule for the wind to modify the commitment of the thermal generation, but used the actual wind schedule for the dispatch. As before, the hydro schedules were not affected by the presence of the wind.

The last two cases, "act-prio" and "fc-prio," were similar to the first and third wind cases in that either the actual or forecasted wind schedule could affect the commitment of the thermal generation. In addition, it was assumed that the forecasted wind schedule was known prior to the development of the pondage hydro schedule. In this way the hydro could be rescheduled to smooth out any "bumps" caused by variations in the wind generation output. The thermal generation was then scheduled for commitment after the wind and hydro.

4.2 Analysis of Results

There are lots of things that happen when new generation of any type is added to the system. This section will examine some of the key areas of energy displacement, emission reductions and impact on transmission congestion in addition to the overall economic impact of the wind additions. Just as important, it will examine how those impacts change based on the wind forecast, its accuracy, how it is used, and the historical wind and load patterns assumed.

4.2.1 Energy Displacement

Figure 4.1 and Figure 4.2 show the energy displaced in the system by the type of technology for the three primary scenarios using the 2001 and 2002 shapes, respectively. In both figures it can be seen that when no commitment credit is taken for the wind generation the bulk of the increases in displacements come from imports and new combined cycle units. This energy is from throughout the three ISO system specifically modeled (NY, PJM and NE) and the "imports" refer to other neighboring systems. When either the actual (no – act) or forecast (no – fc) shapes are reflected in the commitment of the thermal generation there is less impact on the more efficient new combined cycle units.

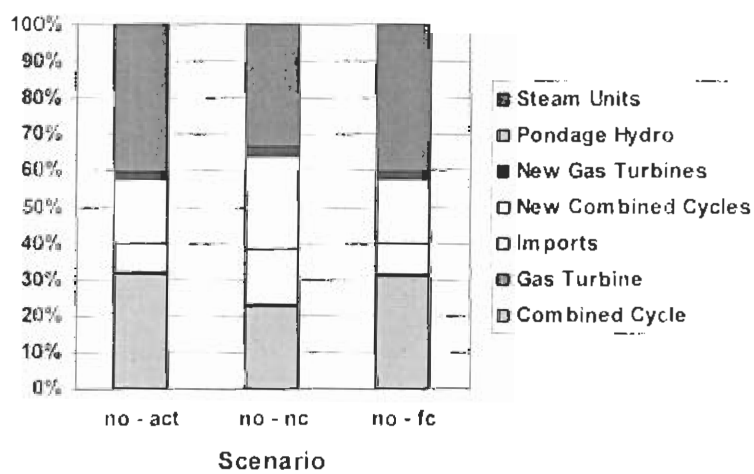

Figure 4.1 2001 Energy Displacement by Technology

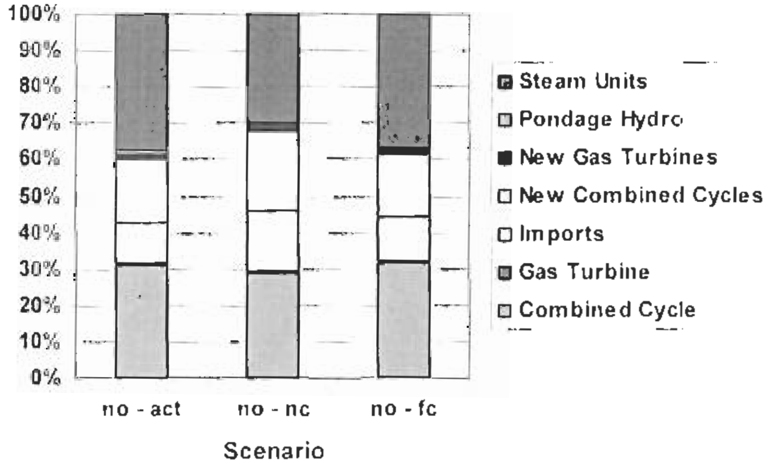

Figure 4.2 2002 Energy Displacement by Technology

Figure 4.3 and Figure 4.4 show a similar comparison by fuel type. When no commitment credit is taken for the wind generation a greater percentage of the displacements come from imports and coal. The coal-fired units are being backed down at night to make room for the wind energy. Recognizing the wind in the day ahead commitment allows the reduction in commitment of oil fired generation and more efficient use of the rest of the system. For the cases analyzed the coal displacement represents roughly .5% to 1% of the overall coal generation. The oil displacement, however, represents anywhere from 5% to 15% of the expected oil fired generation.

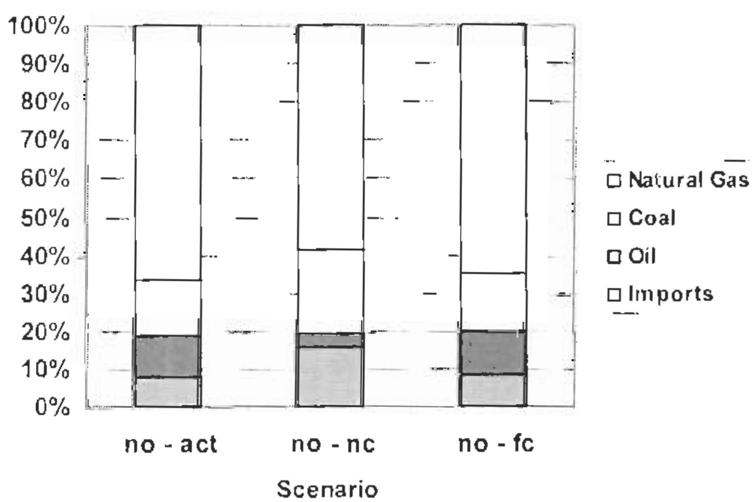

Figure 4.3 2001 Energy Displacement by Fuel

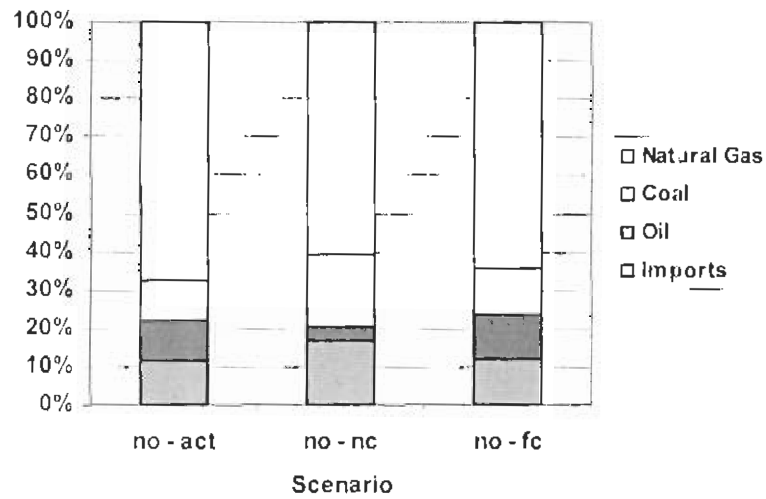

Figure 4.4 2002 Energy Displacement by Fuel

Figure 4.5 and Figure 4.6 show the wind generation and thermal energy displacement for each of the 11 zones in the NYISO. Although much of the wind generation occurs upstate, a significant portion of the energy displaced is downstate.

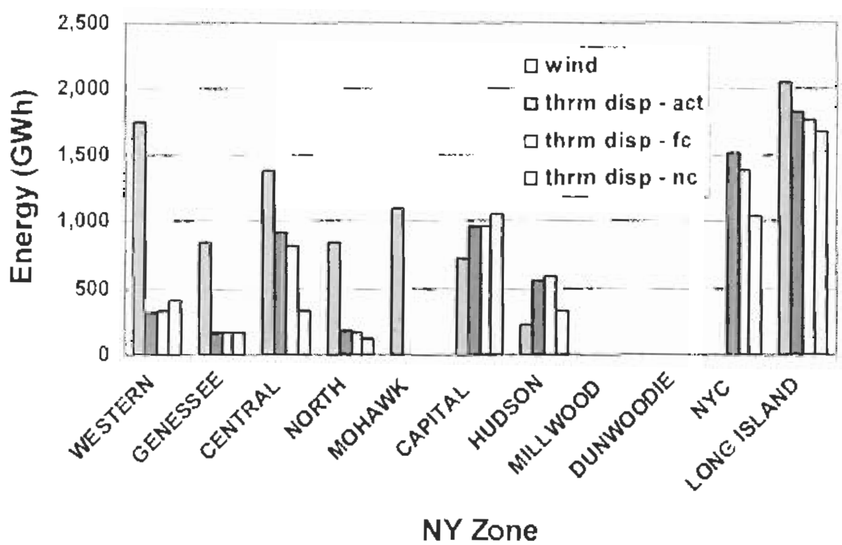

Figure 4.5 2001 Zonal Wind Generation and Displaced Thermal Generation

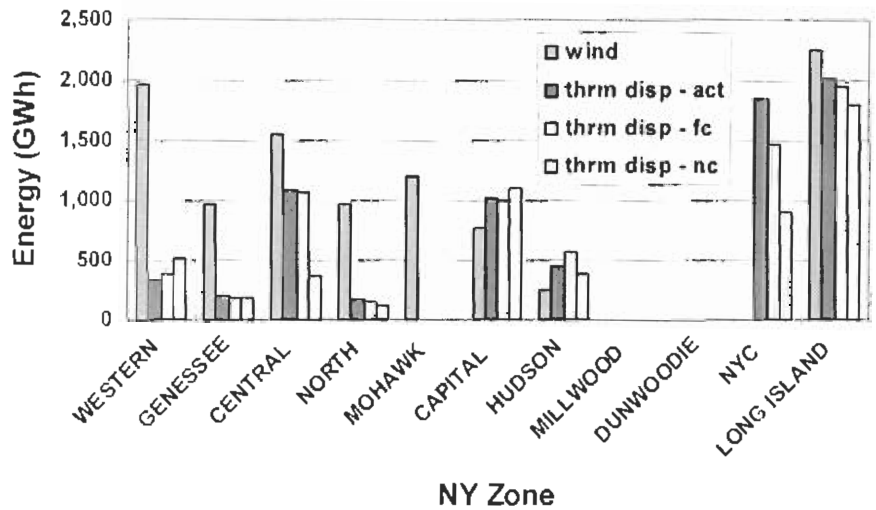

Figure 4.6 2002 Zonal Wind Generation and Displaced Thermal Generation

Figure 4.7 and Figure 4.8 show the regional and total displacement for the NYISO. Even though most of the wind generation occurs in the upstate areas more generation is displaced downstate than upstate. In fact, from the "total" columns it can be seen that the wind generation is significantly greater than the New York displacements for any of the scenarios. This displacement occurs outside of New York with reductions of imports to the state.

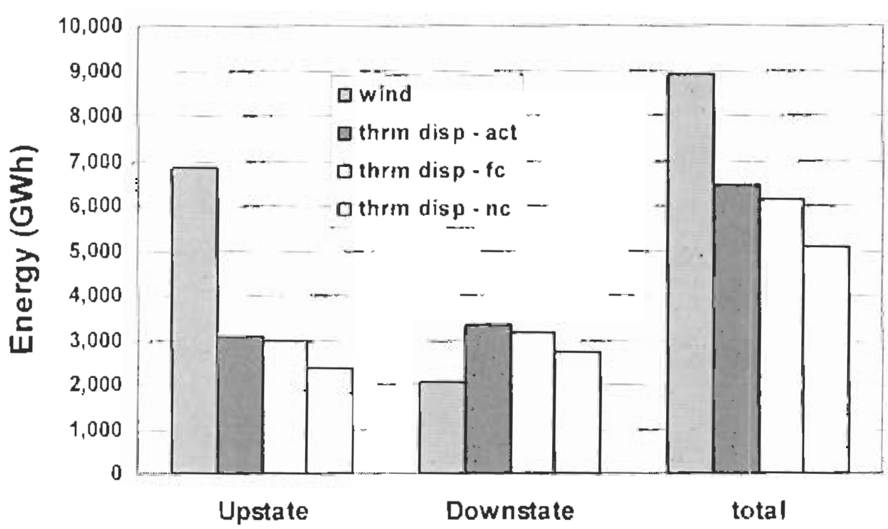

Figure 4.7 2001 Regional Energy Displacement

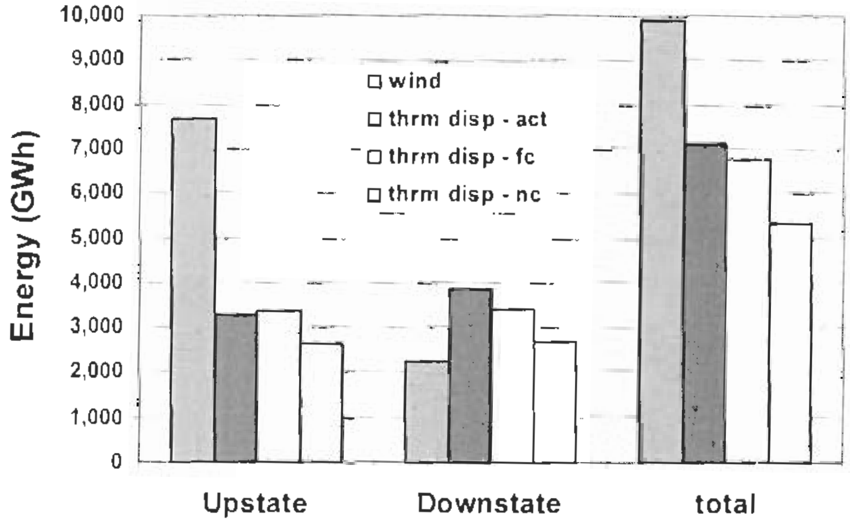

Figure 4.8 2002 Regional Energy Displacement

4.2.2 Emission Reductions

Another key area of interest is the impact on emissions. Figure 4.9 and Figure 4.10 show the impact on NOx and SOx using the 2001 and 2002 hourly data for load and wind. While there are significant reductions in all cases it is interesting to see that the "no commitment credit" actually had higher SOx reductions than the other scenarios. This is consistent with the fact that this scenario displaced more coal-fired generation, which have higher SOx emissions, since the commitment could not be adjusted to remove some of the more expensive oil fired generation.

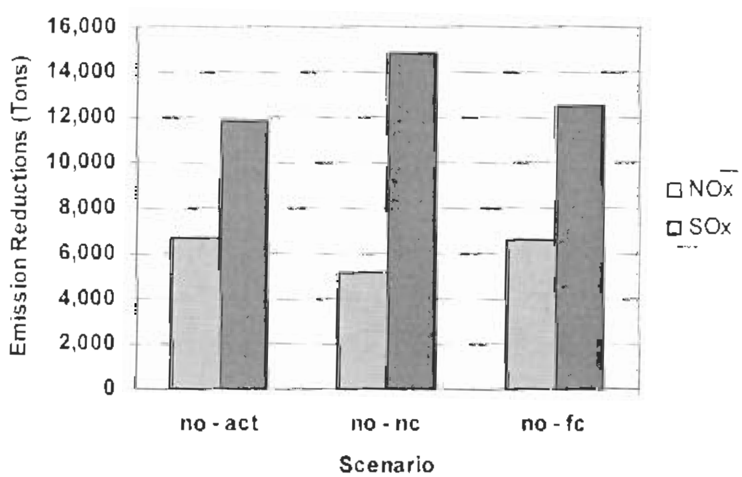

Figure 4.9 2001 Emission Reductions

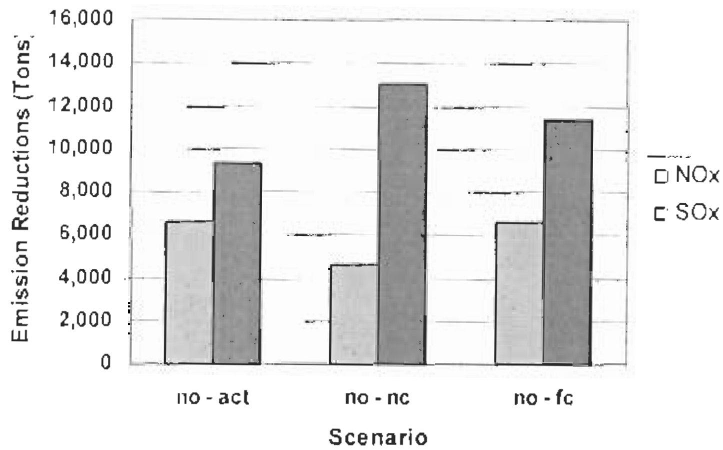

Figure 4.10 2002 Emission Reductions

4.2.3 Transmission Congestion

Because most of the wind generation is located in upstate New York there is an increase in the transmission flows from upstate to downstate. Figure 4.11 shows that the number of hours that the UPNY-SENY (upstate New York to Southeast New York) interface was limiting increased roughly 200 to 300 hours in the cases with the wind generation present.

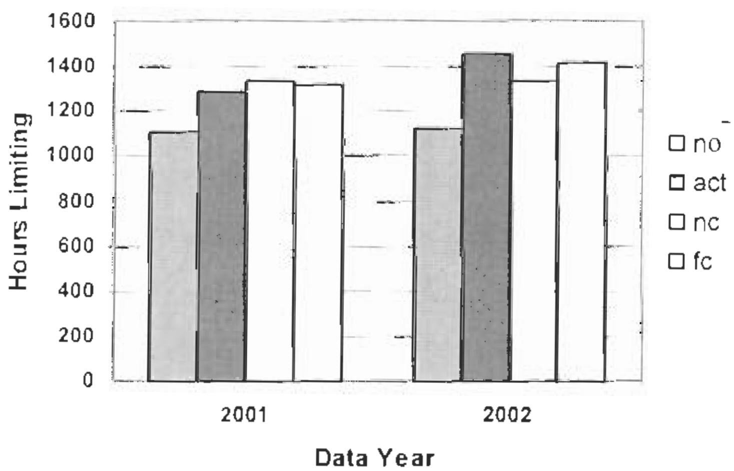

Figure 4.11 Hours Limiting on UPNY-SENY Interface

Although the flat section (limiting hours) is slightly extended, most of the increased flows occurred when the interface was not limiting, as shown for 2001 in Figure 4.12.

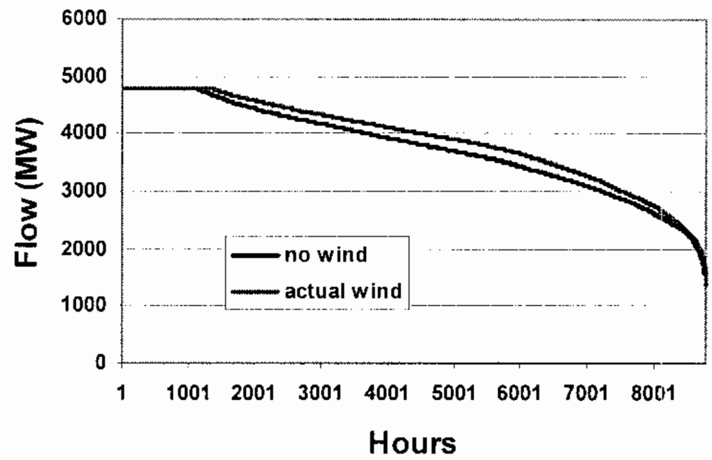

Figure 4.12 Duration Curve of Hourly Flows on UPNY-SENY Interface

The Total East Interface shows a similar increase in flows across the duration curve when wind generation is added to the system. There was roughly a 10% increase in energy flows across the Total East Interface for the scenarios with wind versus without. Figure 4.13 shows that while the interface is not limiting there is a significant increase in energy flows across the year. The addition of over 5000 MW of thermal generation east of the interface (and mostly downstate) in the 2004 through 2008 timeframe for both the "with" and "without" wind cases has produced an overall reduction in the Total East Interface flows from historical levels which were often limiting at 5250 MW.

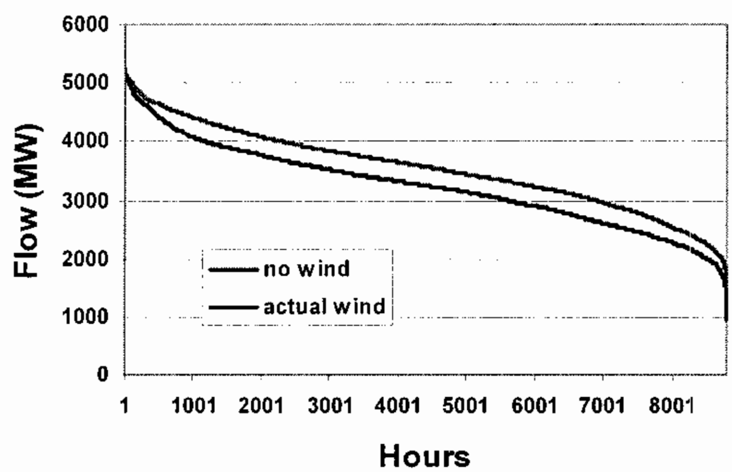

Figure 4.13 Duration Curve of Hourly Flows on Total East Interface

Another measure of congestion is the local spot price in an area. One concern was that excessive wind generation in the low load hours could cause "minimum load problems" whereby the thermal generation would be backed down to its minimum levels, the ties would be saturated and it would be necessary to "dump" excess energy. This is generally evidenced by zero, or even negative, spot prices. Figure 4.14 shows a duration curve of the hourly spot prices in the Genesee area for various scenarios. Although the spot prices are lower in all cases with wind added, as might be expected, there is no block of extremely low hours that would suggest minimum load concerns.

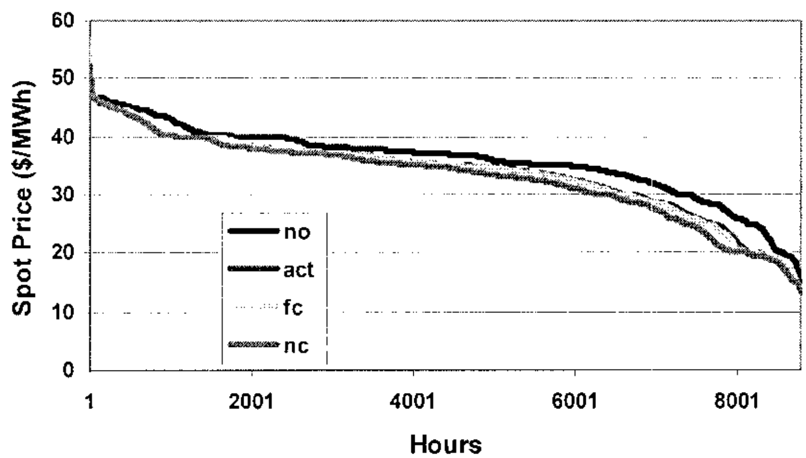

Figure 4.14 2001 Spot Price Duration Curve - Genesee Area

4.2.4 Economic Impact

Although the primary focus of this analysis was reliability and operational issues, the economic impact was also of some interest. Figure 4.15 and Figure 4.16 show various measures of the economic impact for the different scenarios under both the 2001 and 2002 data analysis. Because the 2002 wind shape produced more generation (9,900 GWH vs 8,900 GWH in 2001) the economic impacts tended to be slightly greater with that data. The overall results, however, were consistent between the two years. The 2001 results also included the two additional scenarios where the hydro was allowed to reschedule due to wind generation.

The figures examine the impact on total variable cost, generator revenue and load payments. The first set of columns show the reduction in the total variable cost of operating the system, including fuel cost, variable O&M, start-up costs and emission payments. These variable costs can be viewed as the actual cost savings because these represent the actual reductions in cost. This is opposed to the other columns, which are more "cost allocation" values based on the Locational Marginal Price (LMP) market.

The variations between the columns demonstrate the value of an accurate forecast for the commitment of the balance of the system. The "no commitment credit" case had a variable cost reduction of less than $40/MWh of wind generation while the others were around $50/MWh. Using the forecasted shapes versus the actual shapes produced only a slight reduction in the benefits, but this may be a reflection of the relatively high degree of accuracy in the forecasted shapes. Adjusting the hydro after forecasting the wind provided some slight additional benefits.

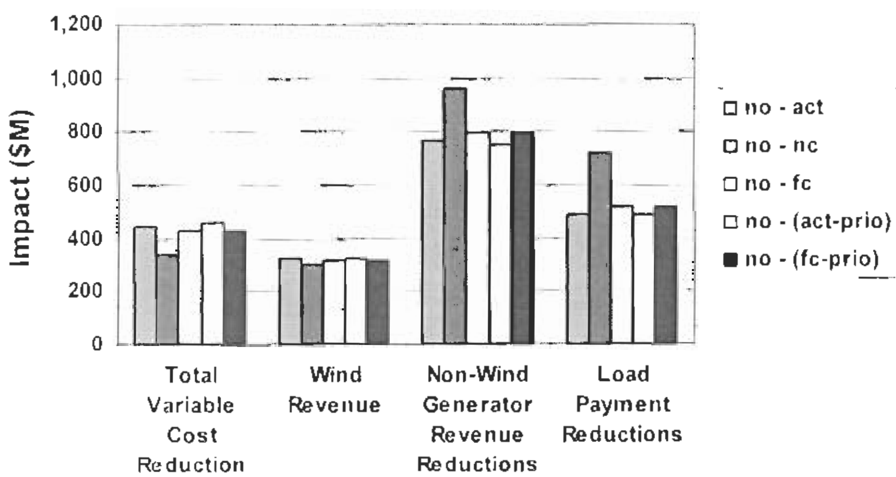

Figure 4.15 2001 Economic Impact

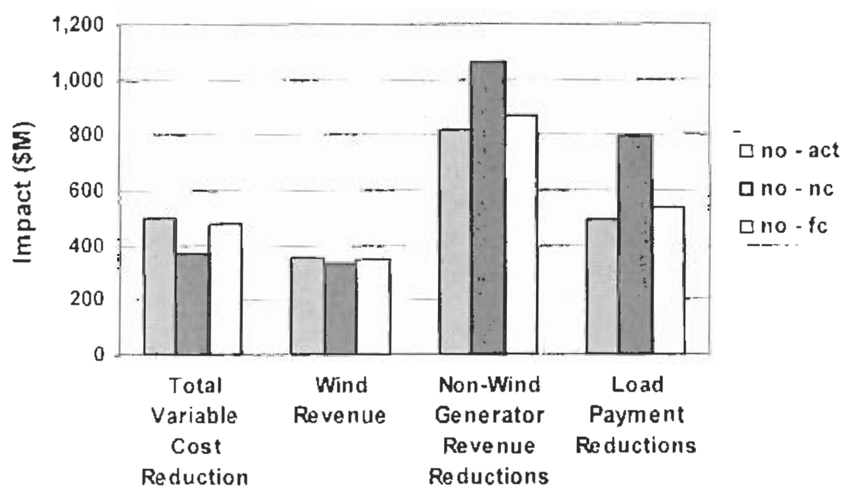

Figure 4.16 2002 Economic Impact

The second set of columns show the revenue generated by the wind plants. This revenue is calculated as the product of the generator output each hour and the corresponding Locational Marginal Price (LMP). Although there was some variation these averaged about $35/MWh for all of the cases.

The third set of columns shows the reduction in revenue for the non-wind generators. The non-wind generators take a double hit in that the wind generation not only displaces some of their energy but also reduces the value of the energy that they do produce. Because the "nc" case did not allow any generation to be decommitted it tended to drive the spot prices lower and produce a significantly greater reduction in the non-wind generator revenues. These values represent about a 4% reduction in the overall non-wind generator revenue in the New York/New England/PJM territory being examined, and about an 8% reduction in just the New York non-wind generator revenue. This 8% was not distributed evenly, however. The analysis showed that the revenue for the residual oil fired generation would be reduced by 20% when comparing the "actual" versus "no wind" scenarios for the 2002 data. There is some concern that this type of impact on certain units may lead to increased retirements that could cause local operational concerns and/or decreased reliability. While valid concerns, these issues were not pursued further in this analysis.

The last set of columns show the reduction in load payments by the Load Serving Entities (LSEs). The load payments are the product of the hourly load and the corresponding LMP. These reductions in load payments are benefits that the consumers receive in addition to the increase in the amount of "green" energy being produced.

Figure 4.17 and Figure 4.18 show the zonal impact within the NYISO. In general, the spot price impact declines as you go west to east and north to south because you are moving farther away from the location of the wind farms. The exception is on Long Island, which has 600 MW of offshore wind generation in the study scenario, and typically high prices due to transmission congestion coming onto the island.

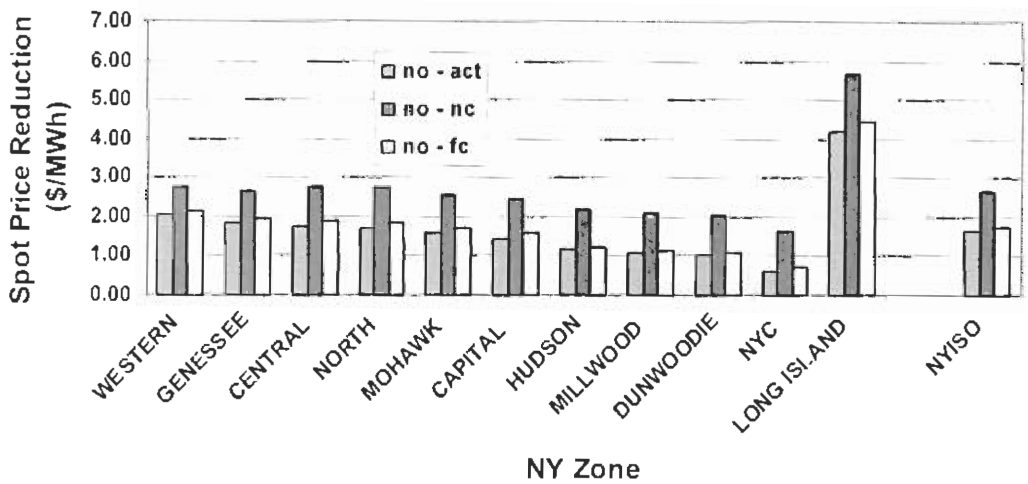

Figure 4.17 2001 Zonal Load Weighted Spot Price Reduction

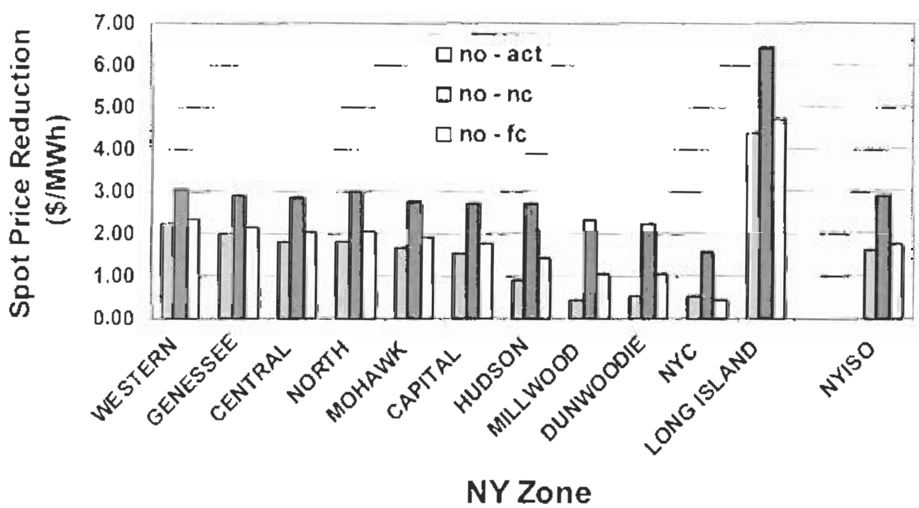

Figure 4.18 2002 Zonal Load Weighted Spot Price Reduction

4.3 Summary

Wind generation has the potential to significantly reduce the cost of system operation in New York while also reducing emissions and dependence on fossil fuels. The zonal spot prices would decrease by a few percent to as much as 10%. The SOx emissions in New York could reduce by 5% and the NOx emissions by 10% with the addition of 3,300 MW of wind generation.

While there was some increase in transmission congestion due to the fact that most of the proposed wind sites are in upstate and western New York, the bulk of the increased flows occurred during times that the interfaces were not fully loaded. In fact, despite the location of the wind farms more downstate thermal generation was displaced than upstate.

The ability to accurately forecast the wind generation for the day ahead market can greatly enhance its value. Roughly 25% of the system cost reductions between the "no wind" and "actual wind" cases results from the ability to predict the wind ahead of time and reflect its generation in the commitment of the rest of the system. The existing forecast accuracy seems to pick up 90% of that difference, but the remaining 10% is worth about $1.50/MWh of wind generation. Based on the data provided, day ahead forecast accuracy is fairly high when viewed across a projected 3,300 MW of wind capacity spread across the state. The accuracy for individual wind farms will not be as high and it may be appropriate for multiple wind farms to merge their forecasts on a zonal or regional basis.

5 Wind and Load Variability

The behavior of power systems is dynamic and driven by continuously changing conditions, to which the power system must continually adapt. The overview of system operation provided in Section 1.3, *Timescales for Power System Planning and Operations*, discussed the various time frames of operation at a high level.

In this section, a detailed statistical analysis of the variability of system loads and wind generation are presented. The results presented here complement the forecast error analysis presented in Section 3, *Forecast Accuracy*. Here, the issue is variation, not uncertainty. The power system must properly respond to these variations, regardless of how well anticipated or predicted they may be.

In the following subsections, progressively shorter periods of time and faster variations in load and wind power will be examined. The time frames correspond to the planning and operation processes outlined in Figure 1.2.

5.1 Annual and Seasonal Variability

There are differences in wind energy production between years. Figure 5.1 shows a duration curve for the three study years. The difference between the minimum and maximum production for the three years is about 1000 GWhr. Similarly, there is seasonal variability as well. To a large extent, these variations are primarily planning issues, rather than operational. Ultimately, issues of long-term variability of wind become significant in the context of economics of operation, capacity planning and to some extend maintenance outage scheduling. The seasonal and annual variability of expected wind production are shown in Figure 7.3. Since these longer-term issues are examined in detail in Section 4, *Hourly Production Simulation Analysis*, and Section 7, *Effective Capacity*, they will not be further discussed here.

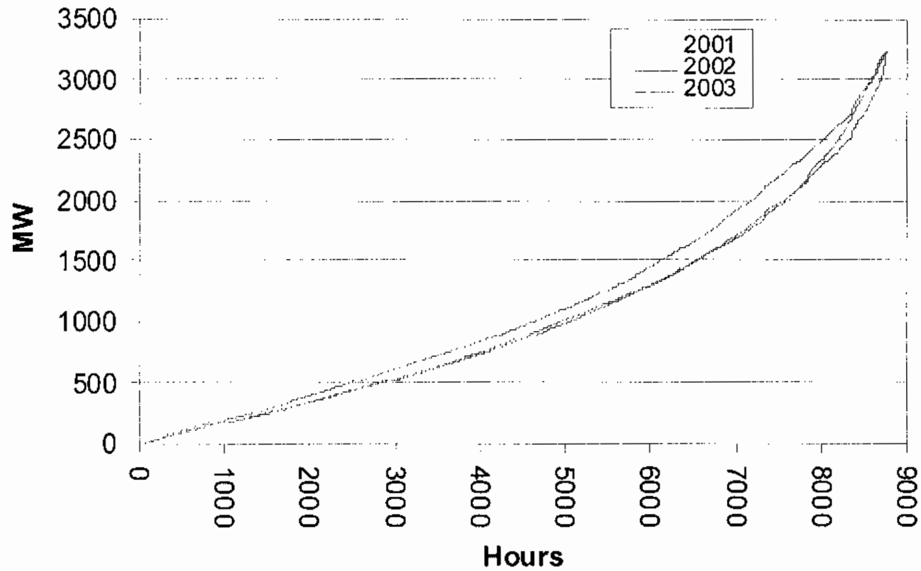

Figure 5.1 Annual Wind Production – Duration Curve

5.2 Hourly Variability

The hour-to-hour changes in system load and, in the future, wind generation, drive operations decisions, especially unit commitment and dispatch, that impact system reliability. In this section, hourly load and wind variability are examined separately and then in combination.

5.2.1 Daily Load Cycle

The daily load cycles within systems exhibit temporal and spatial characteristics that are relatively well understood. Initially in this section a detailed examination of a single day is provided, to give context to the statistics that are presented in the subsequent subsections.

5.2.1.1 Diurnal Characteristics

Figure 5.2 shows a statewide load profile for January 8, 2003 and August 1, 2003. This figure is based on six-second resolution, zonal load data provided by NYISO. These days were chosen as illustrative of winter and summer weekday load profiles. The winter load shape shows the characteristic rapid morning load rise and a second load rise to a daily maximum in the 16:00-19:00 time window of early evening. The summer load profile demonstrates the tendency to peak mid afternoon with later and less pronounced evening load rise. The load profile for each day in New York has qualitatively similar shape, but with different rates of load rise and fall, different magnitude and timing of maxima and minima. The load profiles are examined further in Section 7, *Effective Capacity*.

Figure 5.2 includes over 14,000 data points. Nevertheless, notice that it is relatively smooth, in the sense that fast variations (that make the trace slightly fuzzy) are minimal on this scale.

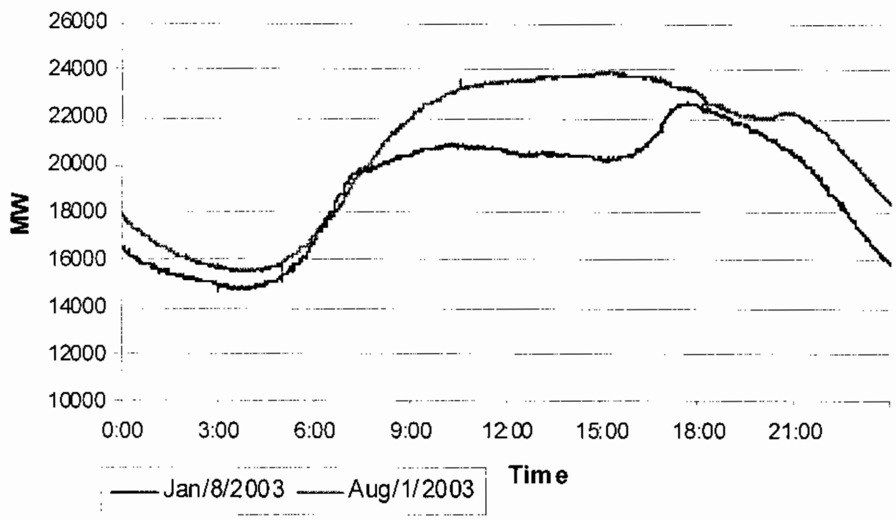

Figure 5.2 State-wide Daily Load Profile for January 8, 2003 and August 1, 2003

5.2.1.2 Geographic Characteristics

The NYSBPS system is segregated into three superzones, and 11 zones, as shown in Figure 1.1. Since Superzone A-E, which covers most of upstate (Zones A through E), is host to the majority of the study scenario wind generation, it is valuable to examine the load characteristics of that superzone separately from the entire state.

Figure 5.3 shows the daily load profiles for the Superzone A-E for January 8, 2003 and August 1, 2003. Notice that the load shapes are qualitatively similar to, but slightly less smooth than, the statewide curves in the previous figure. The daily maxima for the two days are approximately one third that for the entire state. In these figures, it is possible to see some of the finer, high frequency variation in the superzonal load. This faster variation will be examined further in subsequent subsections.

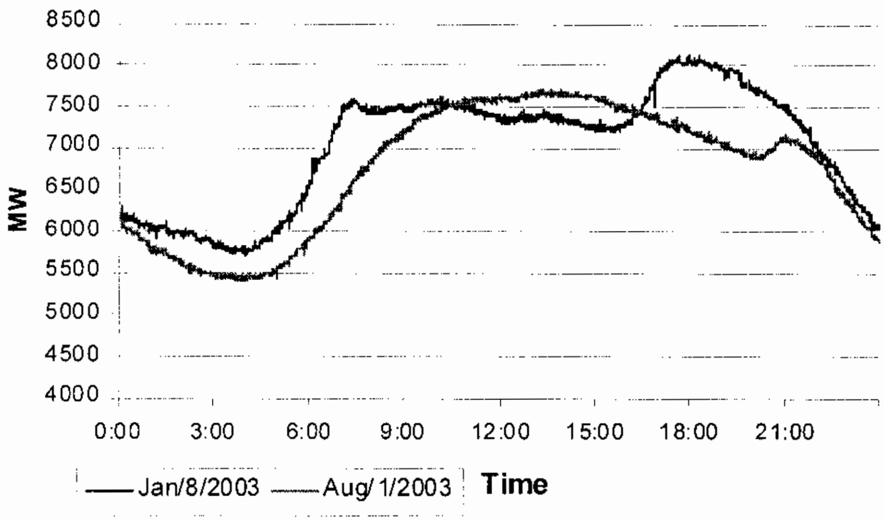

Figure 5.3 Daily Load Cycle for Superzone A-E for January 8, 2003 and August 1, 2003

Zone K on Long Island is host to the other large concentration of wind generation in the study scenario. The wind generation in Zone K is offshore. Figure 5.4 shows the load profile for Zone K. These curves exhibit the general shape of the statewide and superzonal load profiles. The relative maxima are on the order of 10-15% of the statewide load.

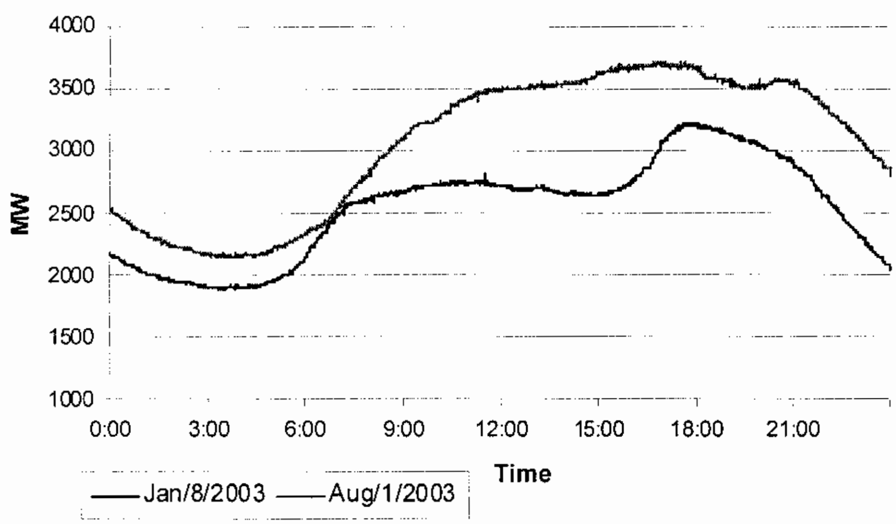

Figure 5.4 Daily Load Profiles for Zone K for January 8, 2003 and August 1, 2003

Each individual zone exhibits its own load profile, with each being similar but not identical to other zones.

5.2.2 Statistical Analysis of Hourly Load Variability

From an operations perspective, a primary concern is securely serving the load as it changes over the day. To the extent that the system has sufficient generating capacity, the major issue is change, rather than the absolute amount of wind power generated. The statistical nature of the hour-to-hour variation of load can be seen in Figure 5.5. In this histogram, the hour-to-hour changes in load power for the entire month (743 hours) are sorted into 200 MW bins. The distribution is roughly normal, with slightly more extremes on the positive (load rise) side.

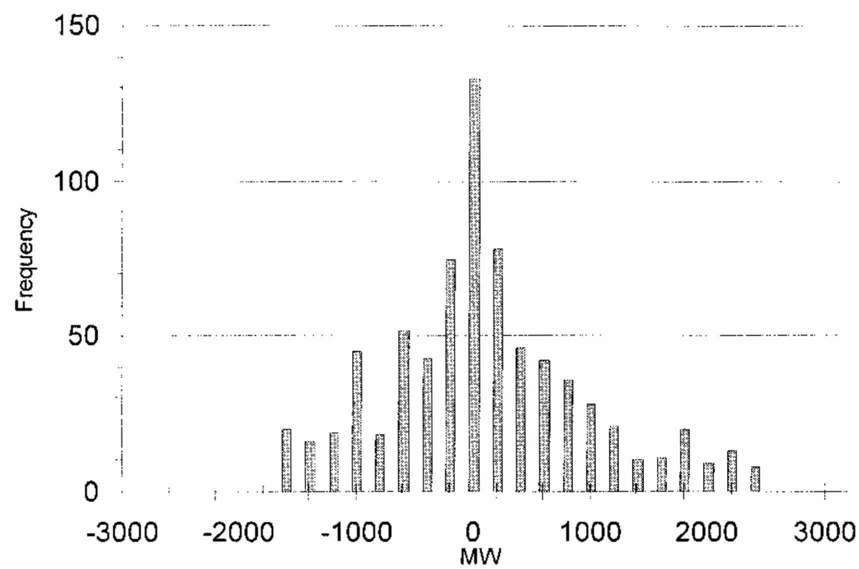

Figure 5.5 January 2001 Hourly Load Change

At the superzone level, the hourly variability histogram shown in Figure 5.6 is narrower; indicating that load rise within Superzone A-E is roughly in proportion to the magnitude of the load served.

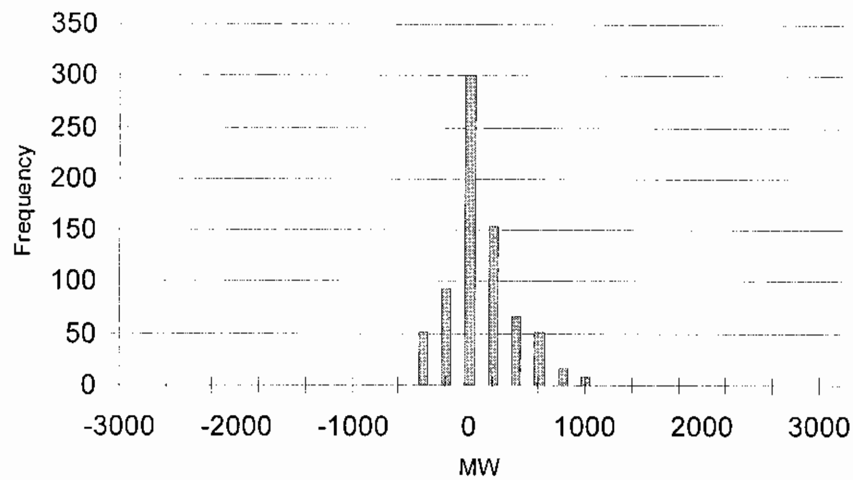

Figure 5.6 Hourly Load Variability in Superzone A-E for January 2001

5.2.3 Temporal Nature of Wind Penetration

The variation in wind production from day-to-day and hour-to-hour also exhibits characteristic diurnal patterns, although the daily patterns are not as orderly as those for load. The monthly pattern shown in Figure 3.4 is illustrative, and typical daily load shapes for the four seasons are shown in Figure 7.3. From an operations perspective, the presence of wind power, taken in isolation, is of little interest. The coincidence of wind generation with load, and the coincident change of load and wind are important, as their combination determines the rate of change that load-following generation must serve.

Penetration of wind generation is often measured on system-level as the ratio of the total installed wind generation to the system peak load. This measure was used in the Phase 1 Report of this project.[vii] However, in many regards, it is the instantaneous penetration that is of interest from an operations perspective. Specifically, conditions of high wind power production combined with relatively low system load can mean substantially larger penetrations than those suggested by the static system-level measure.

Figure 5.7 shows duration curves, for the month of January 2001, individually sorted, by state, Superzone A-E and Zone K. In each of the three traces, the hourly wind and load pairs for the corresponding area are used. So, for example, each point in the superzone penetration curve is that hour's wind generation in the superzone divided by that hour's load in the superzone. The figure shows that on a statewide basis, the study scenario, which has a nominal 10% penetration, only reaches or exceeds 10% for 100 hours in the month. However, the Superzone A-E and Zone K which host most of the wind generation exceed 10% about one-third of the time, and reach penetrations up to 35% on their local basis.

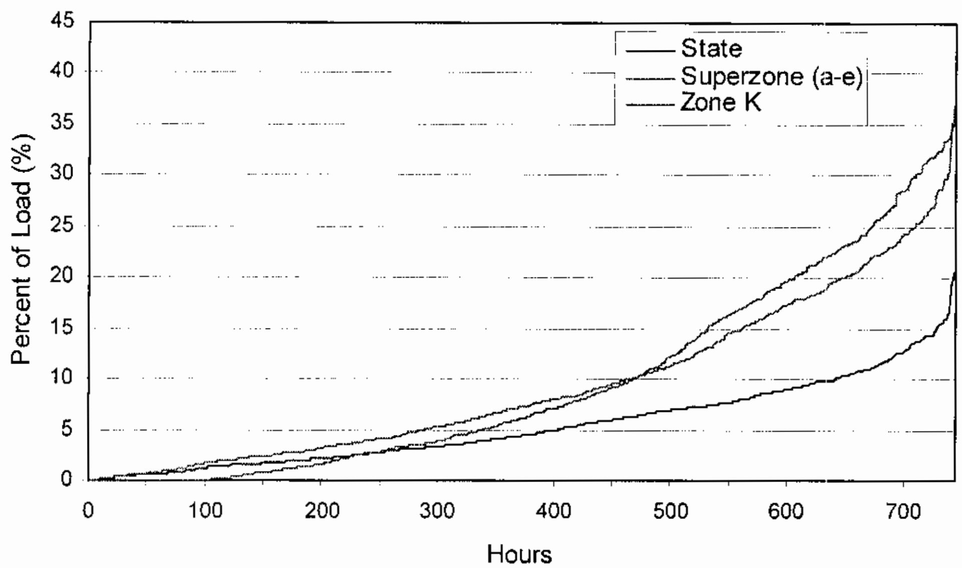

Figure 5.7 Range of Penetration based on actual wind for January 2001

Each month produces a distinct level of penetration, with some number of hours exceeding the nominal 10% penetration level. The hours of penetration in excess of 10% for the eleven months examined in Section 3, *Forecast Accuracy*, are shown in Figure 5.8. The seasonal variation in load and wind generation patterns are apparent in this plot, with fewer hours of penetration in excess of 10% showing up in the summer (August), and more hours during the higher wind months of October and January.

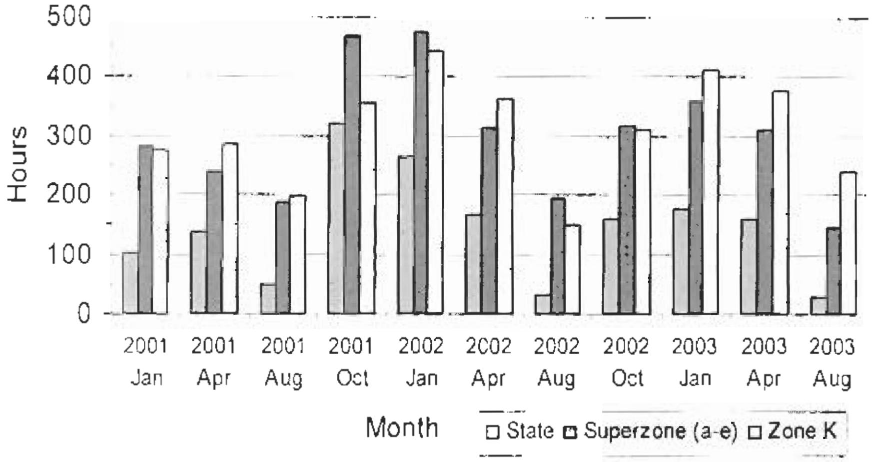

Figure 5.8 Hours Greater than 10% Penetration for Representative (Forecast) Months

5.2.4 Hourly Variability of Wind

The hour-to-hour variability of wind power is shown in Figure 5.9. The bin for this histogram is 100 MW (rather than 200 MW for the load variability histogram) since the magnitude of wind variability is less. This is the variability that corresponds to the actual wind power curve shown in Figure 3.4. There are less than 20 hours in this month when changes in statewide wind generation exceed 500 MW/hour.

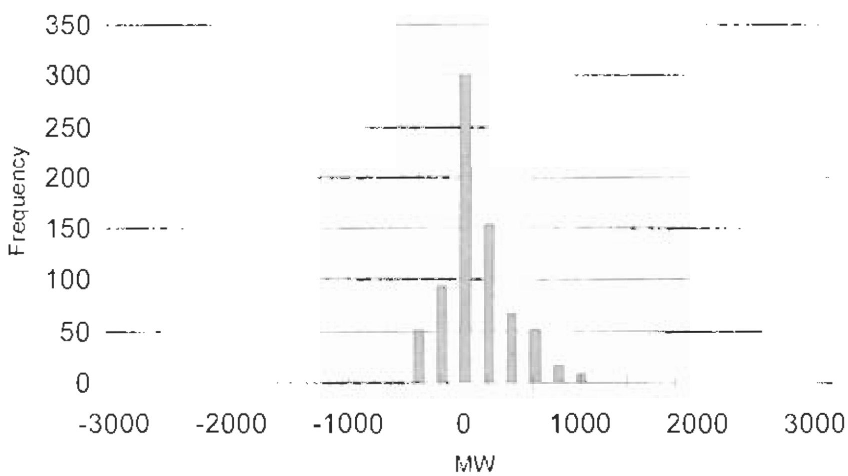

Figure 5.9 Hourly Variability of Statewide Wind Alone for January 2001

5.2.5 Combined Load and Wind Variability

Examination of the hour-to-hour variability of the system with and without wind provides the most insight. Figure 5.10 shows a comparison histogram of the two for January 2001. This figure shows the hour-to-hour changes that must be accommodated by the balance of dispatchable generation in New York State and power exchange with neighboring systems. This figure helps illustrate the fact that variability of wind generation has much the same characteristic as the stochastic variation of loads, for which the system is designed and operated.

Figure 5.10 shows the overall impact of wind generation at the statewide level. The standard deviation of the load only variability for January is 858 MW, increasing by 48 MW to 906 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±2574 MW without wind, and ±2718 MW with wind. In this particular sample, the single largest positive load rise is 2288 MW without wind and 2459 MW with wind. This is consistent with the expectation based on 3σ. The largest single hourly load declines are 1787 MW and 2101 MW, respectively. Stated differently, these results show that the contribution to state-wide hour-to-hour variability of the 3300 MW of installed wind generation are expected to be within about ±150 MW.

Figure 5.11 shows the same information for Superzone A-E. As shown in Figure 5.7 and Figure 5.8, the penetration level within the superzone is significantly higher than that measured statewide. The impact on the hour-to-hour variability within the superzone is more noticeable, with a stronger trend towards larger load rise. The standard deviation of the superzone load only variability for January is 282 MW, increasing by 45 MW to 327 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±846 MW without wind and ±981 MW with wind. In this particular sample, the single largest positive load rise is 871 MW without wind and 1042 MW with wind. This is consistent with the expectation based on 3σ. The largest single hourly load declines are 581 MW and 917 MW, without and with wind, respectively.

Figure 5.12 shows the same information from Zone K. The standard deviation of the Zone K load only variability for January is 144 MW, increasing by 15 MW to 159 MW with wind. This means that within that month, there is a 99.7% expectation (3σ) that hour-to-hour changes will be less than ±432 MW without wind, and ±477 MW with wind. This is supported by this sample, in which the single largest positive load rises were 399 MW and 507 MW, respectively, and the largest single hourly load declines were 318 MW and 401 MW, respectively.

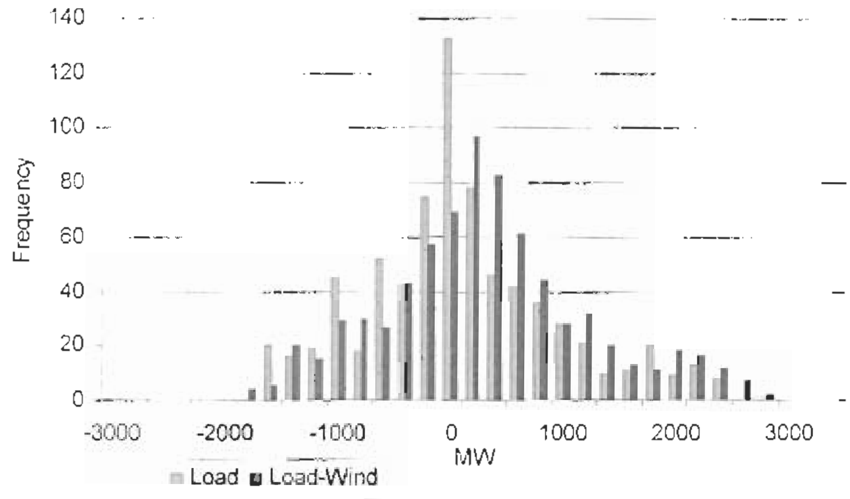

Figure 5.10 Statewide Hourly Variability for January 2001

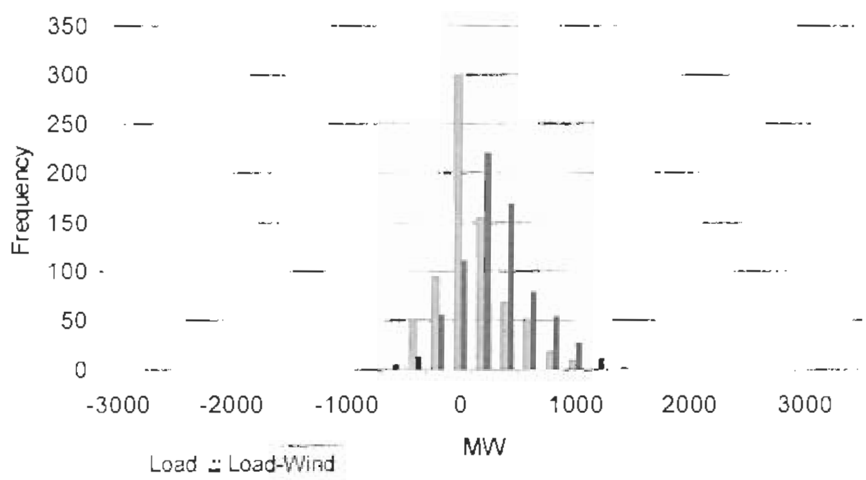

Figure 5.11 Superzone A-E Hourly Variability for January 2001

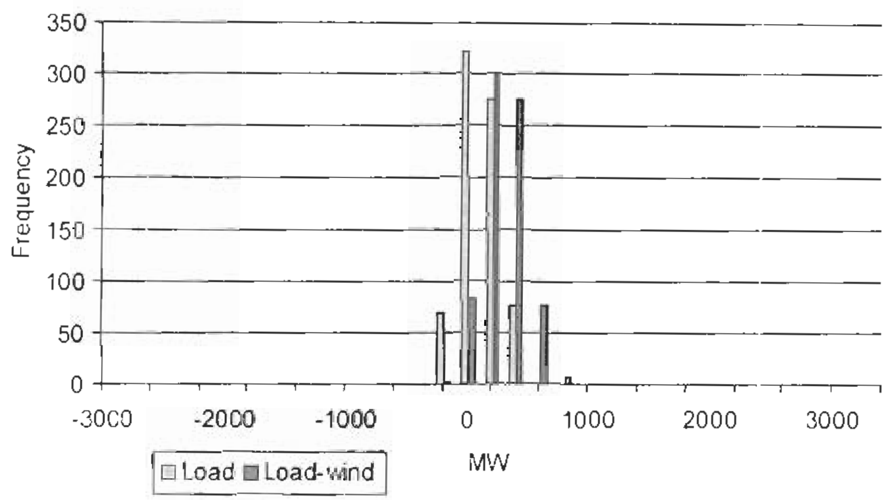

Figure 5.12 Zone K Hourly Variability for January 2001

5.2.5.1 Trends in Hourly Variability

The hour-to-hour variability shown in the figures for January 2001 is representative of that for each month. Figure 5.13 shows the standard deviation for each of the eleven months used for the forecasting analysis. For each month the plots show the standard deviation of hour-to-hour load variability with and without wind for the state, Superzone A-E and Zone K. Thus, for each month, there are six data points. They are plotted against the peak load for that month, for the respective geographical area. Notice that the standard deviation for all months and areas increases due to the addition of wind generation. All the standard deviations also increase with load. The difference between the with and without wind standard deviation in each area grouping is about the same, and not an obvious function of load level. In all months, the hourly increase in variability is small in MW terms. Specifically, the mean standard deviation of the statewide samples increases by 52 MW (6%), from 858 MW to 910 MW; the Superzone A-E samples increase by 45 MW (17%), from 268 MW to 313 MW; the Zone K samples increases by 22 MW (15%), from 149 MW to 171 MW. The production cost impact of these hourly changes was reflected in the analysis presented in Section 4, *Hourly Production Simulation Analysis*, and they are expected to be well within the dynamic capability of the system. This is examined further in Section 6, *Operation Impacts*.

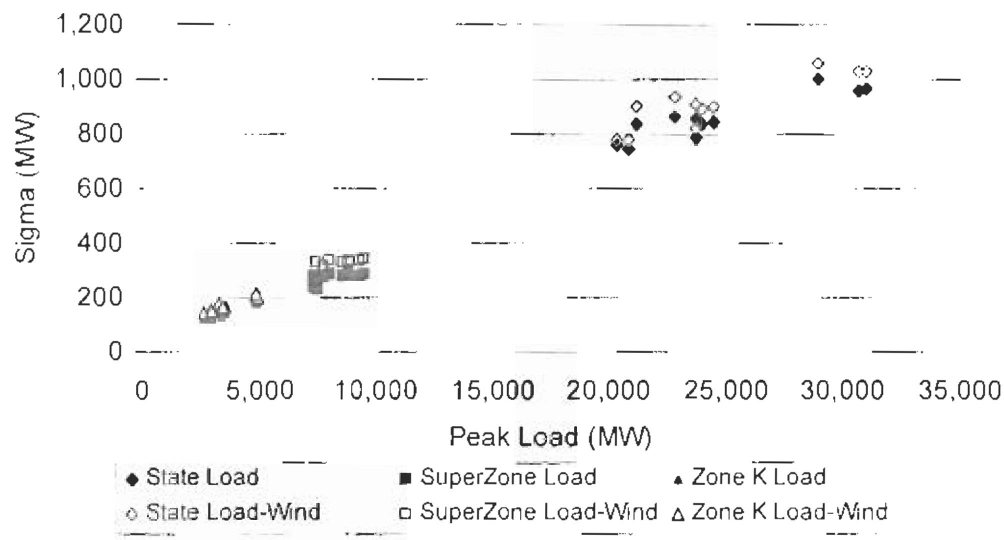

Figure 5.13 Standard Deviation of Hourly Load Variance (by month for 11 sample months)

Detailed statistics for each of the 11 months are included in Appendix C.

5.2.6 Time of Day Trends

Examination of daily and monthly variations tends to mask the impact of variations during periods that present the largest challenge to system operations: periods of rapid load rise. System operators give special attention to periods of peak demand and rapid rise in load. The summer morning load rise, especially during periods of sustained hot weather, presents one of the more severe tests to the system. The tendency of wind in New York State to decline during periods of rapid load rise prompts concern about the ability of the system to respond. Figure 5.14 shows the hour-to-hour variability for the summer morning load rise period. The data plotted is for all mornings during June through September for the three years of system data (2001-2003). There are three data points per day, the delta from 7:00 to 8:00 am, 8:00 to 9:00 am and 9:00 to 10:00 am. Unlike Figure 5.10, this distribution is not centered around zero. Essentially all values are positive, as would be expected for a load rise period. During this load rise period, it is not unusual for the state to experience load rise rates in excess of 2000 MW/hour. The figure shows that the tendency of wind generation to fall off during this period does indeed cause the distribution to trend towards higher rates of rise. In this sample of 1099 hours, 31% of the hours have rise rates ≥ 2000 MW/hr without wind, with the worst single hour rising 2575MW. With wind, this increases to 34% of hours with rise rates ≥ 2000 MW/hr, and a worst single hourly rise of 2756 MW.

Figure 5.15 shows a similar set of data corresponding to the winter evening load rise. Again, the presence of wind generation pushes the trend towards higher rates of load rise. The number of hours with rise rates ≥ 2000 MW/hr, increases from 2% to 4%, with the single worst hour changing from 2087 MW/hr to 2497 MW/hr. In each of these windows of time, system generation needs to be ramped up to follow this load rise. The presence of wind generation will increase this requirement. Overall, the impact on the load following requirement is relatively small compared to the existing requirement, which the New York State system presently meets. The performance of the system during such periods of high rate of load rise is examined further in Section 6, *Operational Impacts*. Statistics for the distributions shown in Figure 5.14 and Figure 5.15 are provided in Appendix C.

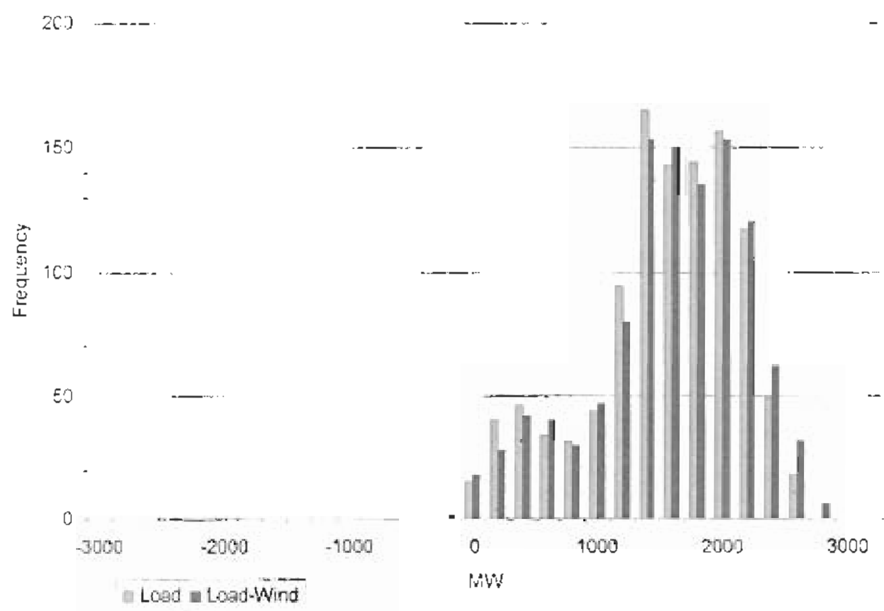

Figure 5.14 Summer Morning Load Rise - Hourly Variability

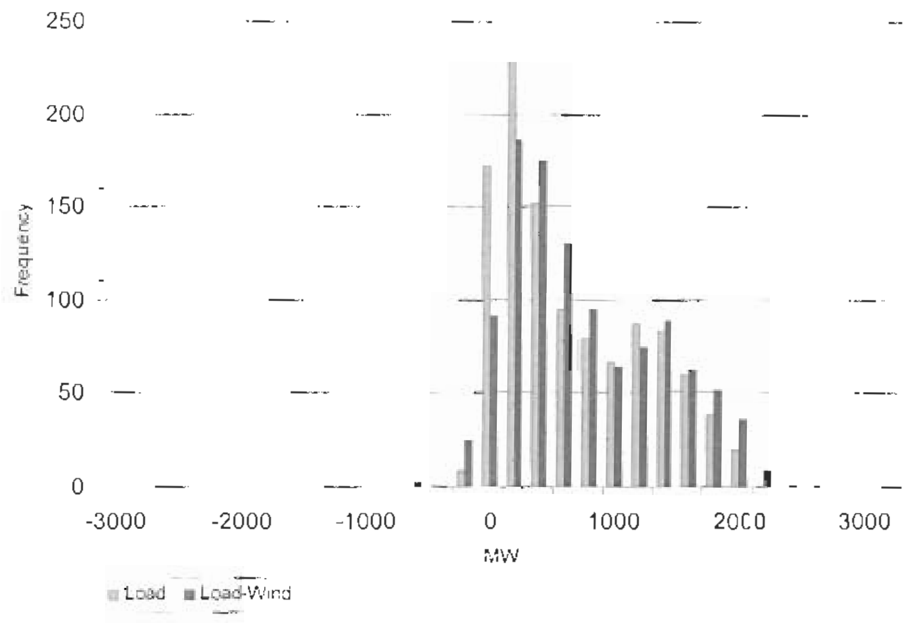

Figure 5.15 Winter Evening Load Rise - Hourly Variability

5.3 Five-Minute Variability

The analysis presented in the previous subsection shows that the hour-to-hour variability of the NYSBPS with wind generation is only slightly impacted. However, that data does not address system behavior within each individual hour. Within each hour, NYISO performs an economic dispatch at five-minute intervals, and adjusts the schedule on a subset of the generating plants within the state accordingly. Thus, system variation on these five-minute load-following intervals is critical to system operations.

In this section, a sample of three-hour windows of operation is analyzed. These three-hour sample windows are extracted from the six-second resolution load data provided by NYISO and the one-minute resolution wind data provided by AWS. Figure 5.16 shows a statewide histogram of five-minute load changes without and with wind for eighteen three-hour windows for which coincident wind and load data was available. The data includes samples from days in January, April and August. The statistical bins are 25 MW. Figure 5.17 shows the same samples for Superzone A-E and Figure 5.18 shows the distribution for Zone K.

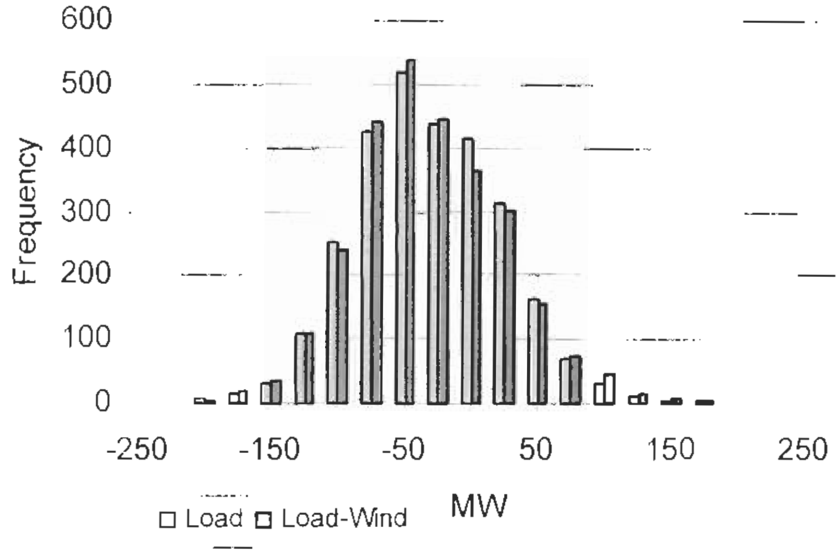

Figure 5.16 Five-minute Variability Statewide

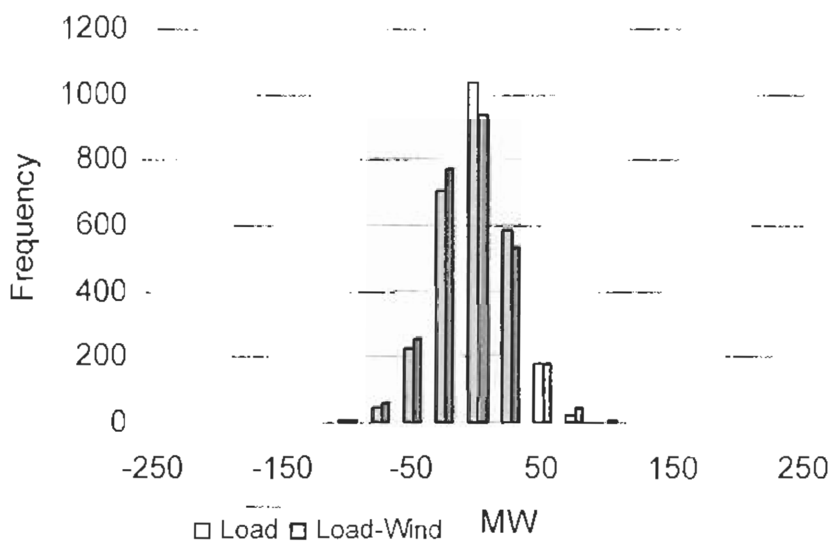

Figure 5.17 Five-minute Variability for Superzone A-E

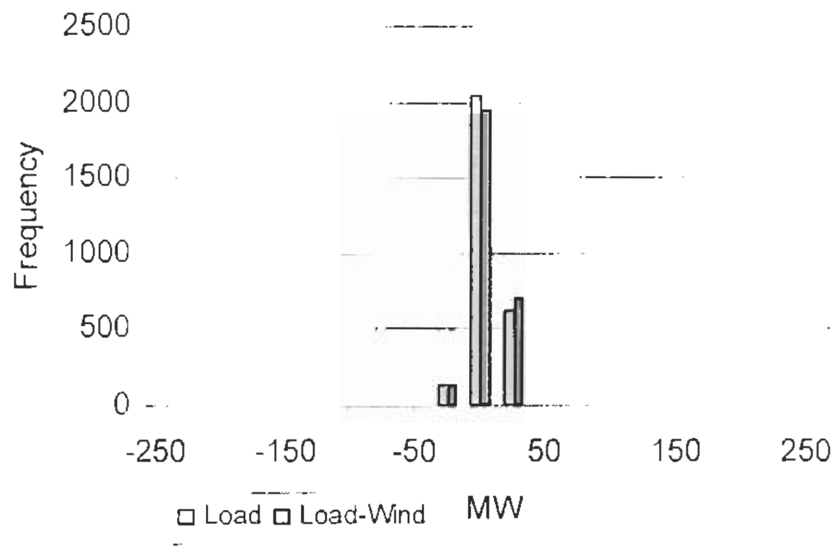

Figure 5.18 Five-minute Variability for Zone K

As expected, the geographic diversity of the wind sites causes the impact of wind generation on the five-minute variability to be quite small. Overall, there is a slight increase in the variability in each of the geographic areas. Specifically, the standard deviation of the statewide samples increases by 1.8 MW (3%), from 54.4 MW to 56.2 MW; the Superzone A-E samples increase by 2.2 MW (8%), from 27.5 MW to 29.7 MW; the Zone K samples increases by 0.5 MW (5%), from 11 MW to 11.5 MW. State-wide, the single largest positive load rises were 165 MW and 167 MW, respectively, without and with wind. For Superzone A-E, the largest single hourly load rises were 142 MW and 135 MW, respectively (i.e., lower with wind than without). And for Zone K, the largest single hourly load rises were 33 MW and 31 MW, respectively (also lower with wind than without). Appendix C includes similar plots for periods of high wind volatility and for selected high wind change events. Overall, the impact on five-minute variability is relatively small, and not expected to have substantial impact on load following. This is examined further in Section 6, *Operational Impacts*.

5.4 Six-Second Variability

Variation in system load during the intervals between five-minute economic dispatch adjustments are primarily handled by system regulation as directed through the automatic generation control (AGC).

The load characteristics shown in Figure 5.2 through Figure 5.4 for one day include information about these rapid variations in system load. However, the second-to-second variations in those figures are not of significant amplitude to be understandable compared to the larger and slower variations characteristic of the daily load cycle. Since the system is redispatched at five-minute intervals, variations within those intervals are indicative of the regulation requirement on the system.

Figure 5.19 shows the statewide load variation with respect to a five-minute running average for January 8, 2003. This plot effectively filters out the slower variations that are addressed by the load-following and day-ahead dispatch, leaving the fast fluctuations (across adjacent six-second periods) for which system regulation is needed. In this figure, variations on the order of +/- 50 MW can be seen at a more-or-less continuous level across the entire day. This variation is slowly biased up and down during the load cycle. For example, during periods of high rate of load rise (e.g., around 6:00 am and 5:00 pm), the curves tend to be above zero, and during load drop periods they tend to be negative.

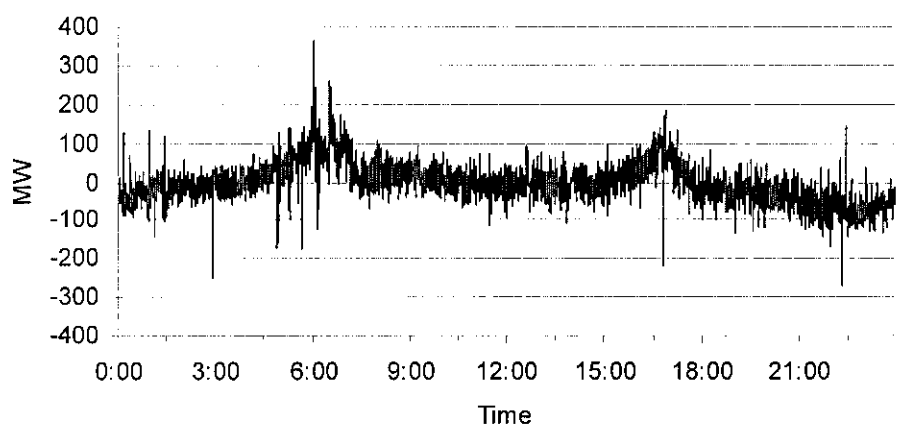

Figure 5.19 State-wide Load Variation Around Five-minute Running Average for January 8, 2003

Figure 5.20 shows the same information for Superzone A-E. It is interesting to note that the 'envelope' bounding most of the fluctuations is only slightly lower in magnitude (roughly +/- 30MW) than for the entire state, even though the total load in the superzone is about 1/3 that of the state as a whole. The trend continues to smaller and more granular areas of the system, as can be seen Figure 5.21, which shows the variation for Zone K only. This is an indication of the fact that these fast variations are relatively uncorrelated across the system. Thus, the larger the number and geographic diversity of the loads in the sample, the smaller the relative magnitude of the variation. All three of the figures show occasional spikes up or down. These can be due to major load start/stop events, minor system disturbances, or data anomalies. This small sample shows that occasional steps in load of hundreds of MW are part of normal system operations in New York State.

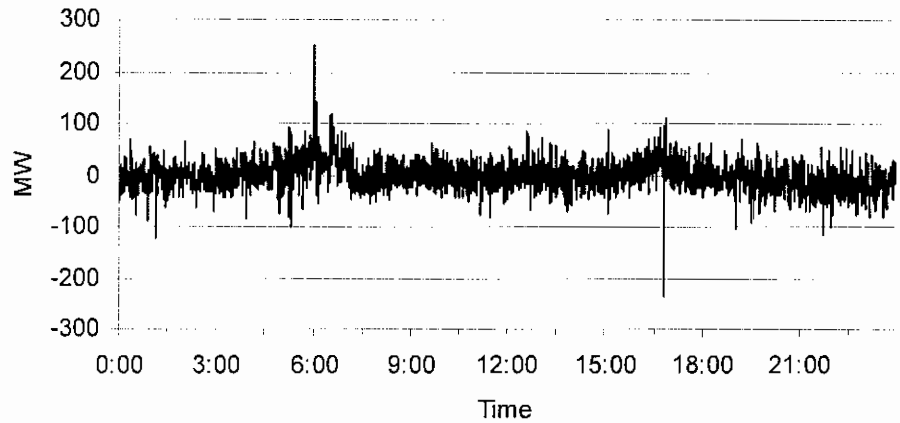

Figure 5.20 Superzone A-E Load Variation Around Five-minute Running Average for January 8, 2003

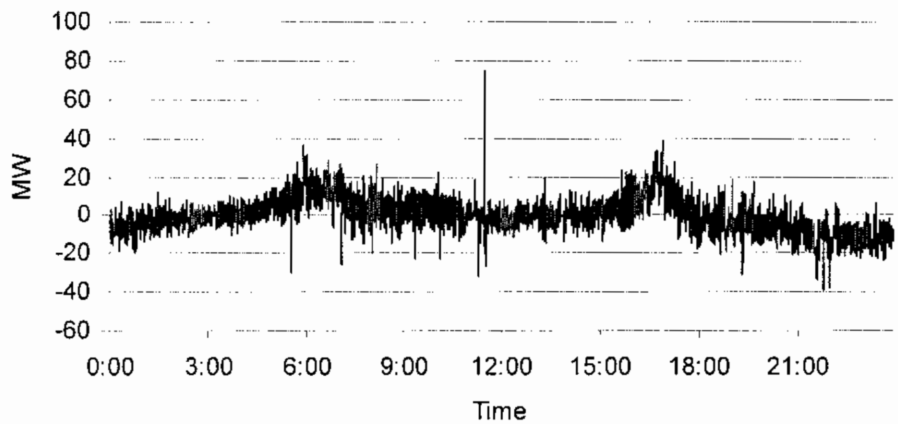

Figure 5.21 Zone K Load Variation Around Five-minute Running Average for January 8, 2003

The statistical characteristics of each zonal variation are shown in Figure 5.22. The data includes analysis of the two days shown in Figure 5.2 through Figure 5.4, and six other representative days (comprised of a weekend and week day from each season). Appendix C includes tables of all the statistical details of the fast load variability for these eight sample days. Notice that there is a moderate spread of standard deviations between zones and across individual days, but that overall the behavior is fairly consistent and shows no obvious correlation with season or day of the week. The total variability for Superzone A-E is much less than the arithmetic sum of the standard deviations from the constituent zones (A through E). This is even more obvious with the state total, and is confirmed with the other statistics included in Appendix C. The statewide standard deviations range in the neighborhood of 35 MW to 55 MW, statistically indicating that 99.7% of 6-second variation will be within three times this level.

The overall conclusion to be reached from this figure is that there is relatively little daily or seasonal variance in the required regulation for the state. There are occasional outliers observable at the zonal level. These occur during non-peak load periods, which tends to support the observation that regulation requirements are not strongly correlated to load level.

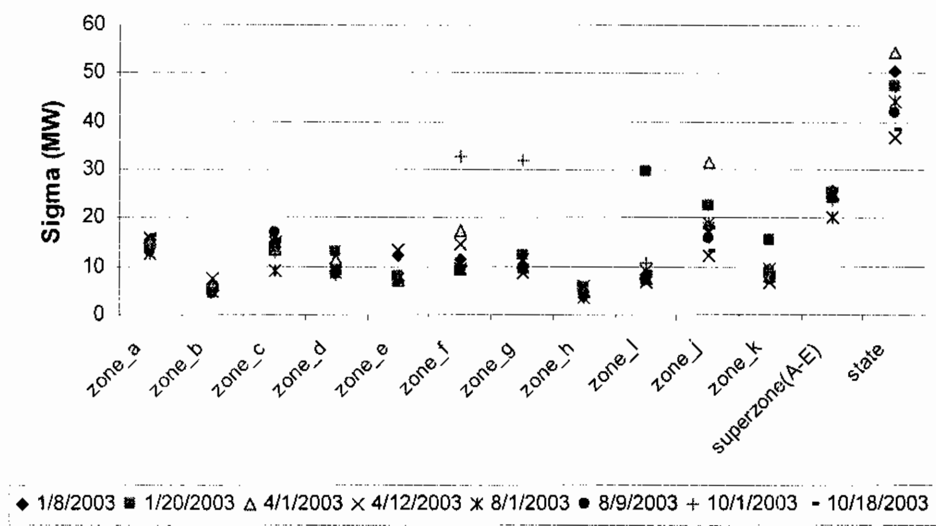

Figure 5.22 Six-second Variation by Zone, for Various Sample Days

5.4.1 AGC Performance

The automatic generation control, AGC, responds to departures from scheduled power interchange between New York State and the neighboring systems and deviations from nominal 60 Hz frequency. The AGC sends updated power setpoint commands to generating units on AGC at six-second intervals. The measure of deviation from schedule is area control error, (ACE), which has units of MW. There is a correlation between the amplitude of the ACE and the amount of regulation required to meet regulation performance objectives such as NERC Control Performance Standards, CPS1 and CPS2[viii].

Figure 5.23 shows the New York State ACE for January 8, 2003. It is interesting to note that the amplitude of the high frequency variations in this trace is quite similar to that of the fast load variations shown in Figure 5.19. Given that the ACE has other, mostly slower variations also present, it is clear that there are other factors beyond load variation driving the ACE as well. These are probably related to generation ramping and changes in interchange with the neighboring systems.

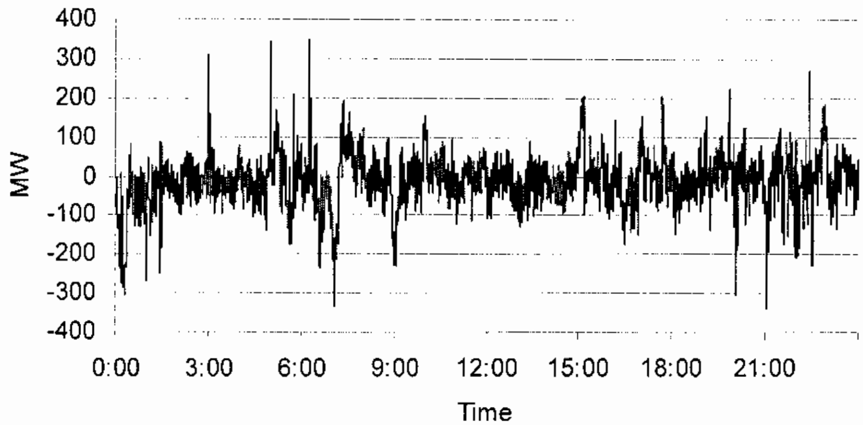

Figure 5.23 NYISO ACE for January 8, 2003

A histogram of the same day's ACE is shown in Figure 5.24. The distribution uses 25 MW statistical bins, with most values of ACE falling in the range of +/- 75MW. The standard deviation for this distribution is 67 MW.

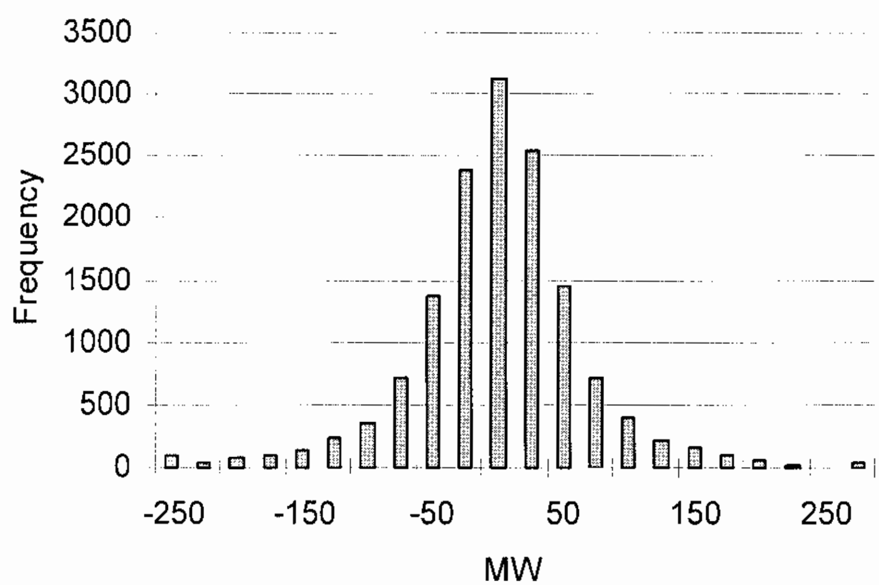

Figure 5.24 Histogram of ACE values for January 8, 2003

The variation in ACE is fairly uniform over the day, with slightly higher values observed during periods of maximum load rise and fall, as expected. The behavior of ACE does not change substantially across seasons or day of the week, as is shown in Figure 5.25.

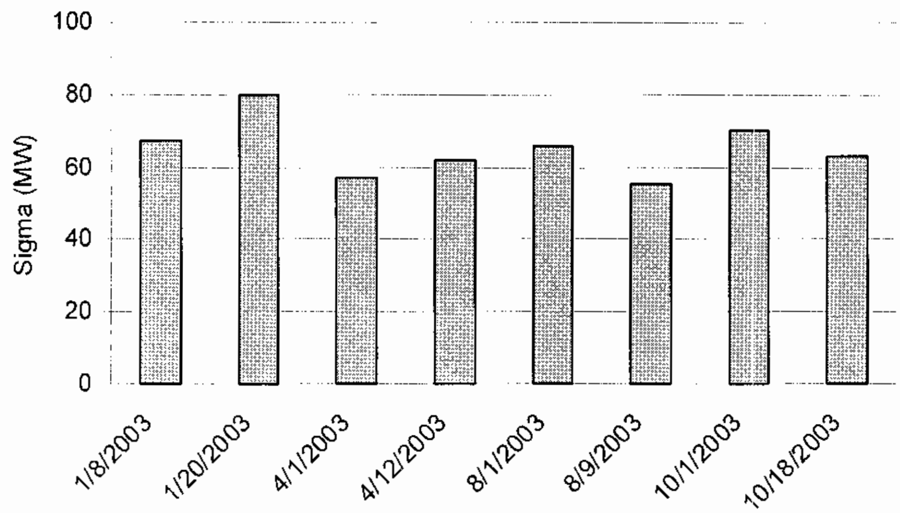

Figure 5.25 Distribution of ACE Standard Deviation

Table 5.1 shows a complete summary of the statistics on ACE for the eight representative days. The figure and table shows that the standard deviation on ACE is generally in the neighborhood of 75MW. Since the system needs to be operated so that ACE can be periodically driven through zero, there must be sufficient regulation power available from generation under AGC to cancel out ACE. Statistically (as noted above), three standard deviations will cover roughly 99.7% of events. New York State operating practice is to retain 225 to 275 MW of regulation power.[ix] This seems consistent with an ACE standard deviation on the order of 50 to 80 MW. This is also consistent with a load deviation (from Figure 5.22), which is in the neighborhood of 35 to 55 MW.

Table 5.1. ACE Statistics from Eight Representative Days

	8-Jan	20-Jan	1-Apr	12-Apr	1-Aug	9-Aug	1-Oct	18-Oct
00:05 - 23:59	ACE	ACE	ACE	ACE	ACE	ACE	ACE	ACE
Mean	-13.38	-38.60	-6.98	-2.82	-11.69	-6.43	-1.42	-5.23
Standard Error	0.56	0.67	0.48	0.52	0.55	0.46	0.59	0.53
Median	-11.67	-32.00	-12.17	-4.00	-9.33	-4.00	2.17	-4.50
Mode	-7.00	-70.00	5.00	0.00	9.00	23.00	2.00	-23.00
Standard Deviation	67.46	79.98	57.31	62.20	65.93	55.49	70.08	63.05
Sample Variance	4550.83	6396.63	3283.97	3868.25	4347.42	3079.58	4910.85	3975.68
Kurtosis	3.57	2.84	4.49	0.95	3.36	1.76	1.78	1.35
Skewness	-0.26	-0.69	1.20	0.06	-0.31	-0.60	-0.37	0.12
Range	691.40	859.00	612.83	620.20	650.17	415.33	762.58	592.00
Minimum	-342.40	-504.00	-258.33	-321.00	-306.67	-252.33	-373.33	-292.50
Maximum	349.00	355.00	354.50	299.20	343.50	163.00	389.25	299.50
Sum	-191939.81	-553863.78	-100102.08	-40481.81	-167723.98	-92304.18	-20391.02	-75078.70
Count	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00	14349.00

5.4.2 One-Second Wind Variability

The variability of wind power in the one-second time frame is statistically uncorrelated between sites[x]. Six one-second resolution wind data sets were analyzed for their second-to-second variability. Figure 5.26 shows the standard deviation of second-to-second changes for each of the scenario wind sites, for each of the six 10-minute wind samples. In the figure, each color/shape corresponds to one of the samples for all of the sites. The individual sites are plotted against the project rating on the x-axis. Notice, that for any given sample, there is a wide range of variability, even between projects of similar size. This would be expected for a short sample like this. Notice also that variability, while increasing with project size, does not increase in proportion to project size. This is again because the spatial diversity within a large farm is quite important in this time frame, and results in significant smoothing for large projects. The largest site (600 MW) is offshore, and so also benefits from somewhat steadier wind than on-shore sites. The heavy brown dots are for the wind sample used in stability simulations presented in Section 6.2, *Stability Analysis*. In additional to these spatial diversity benefits, the second-to-second variability from individual wind turbines is limited by their physical characteristics. Wind turbines have significant inertia, which limits the rate at which power output can change. Further, the electrical and control characteristics of wind turbine generators have a significant impact on the relationship between wind speed fluctuation and electric power output.

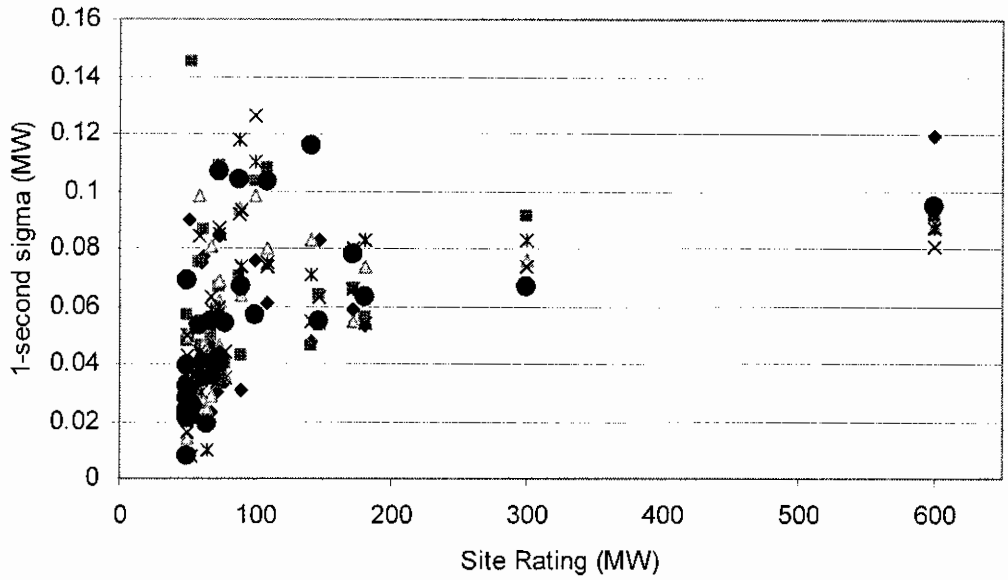

Figure 5.26 Variability Statistics (One-second) for Samples

5.4.2.1 One-Second Wind Variability Of One Wind Farm

The second-to-second variation in output of a specific wind farm is a highly localized phenomena. Historical measurements at other locations and meso-scale meteorology can provide some level of insight into the expected behavior of a farm. In this section, detailed statistical analyses of an operating farm are presented. The data is one-second resolution data for an approximately 100 MW farm in Iowa[xi]. The total farm output for the month is shown in Figure 5.27. There are about 2.7 million data samples plotted in this figure, which clearly shows substantial variation in output over the month. This output looks highly variable, but recall that this is 744 hours (31 days). In this context, we are concerned with second-to-second variations within 10-minute windows.

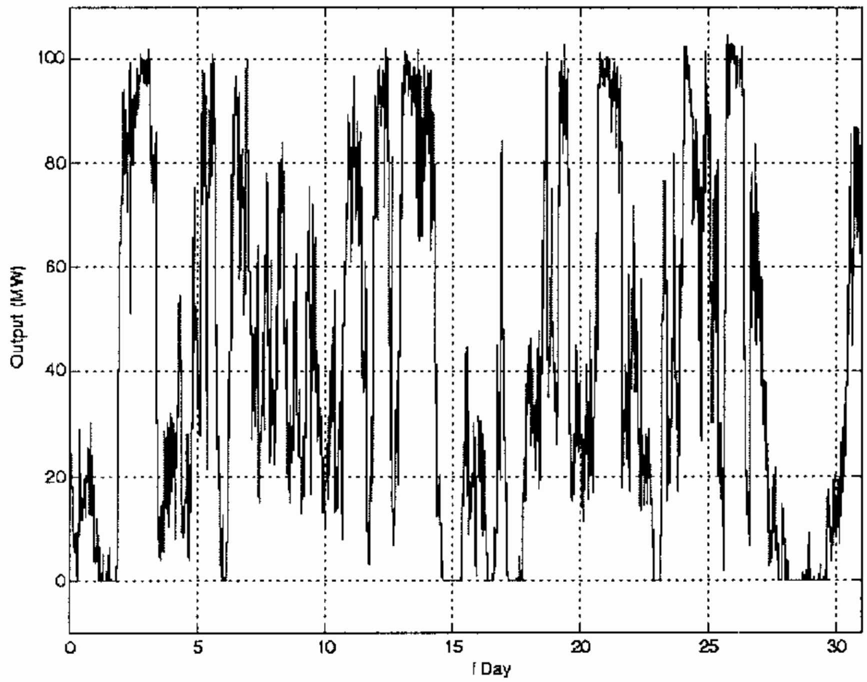

Figure 5.27 One Month of One-second Resolution Data from Operating Wind Farm

Figure 5.28 shows the second-to-second change for the output plotted in Figure 5.27. Notice that at no time in the month did a change in excess of 1 MW, roughly 1%, occur in a second. Most changes are much smaller. In terms of system stability, a 1% step change is normally trivial.

It is possible for individual wind turbines to trip within a farm, due to local equipment problems or due to high winds. In such cases, a step decrease of up to the rating of a single wind turbine is possible, though no such event is identifiable in this sample. In general, tripping due to high wind will occur one wind turbine at a time over a farm. High wind speed cutout was considered in the development of the statewide wind scenarios, but is not a major contributor to the largest system changes in any of the operational time frames.

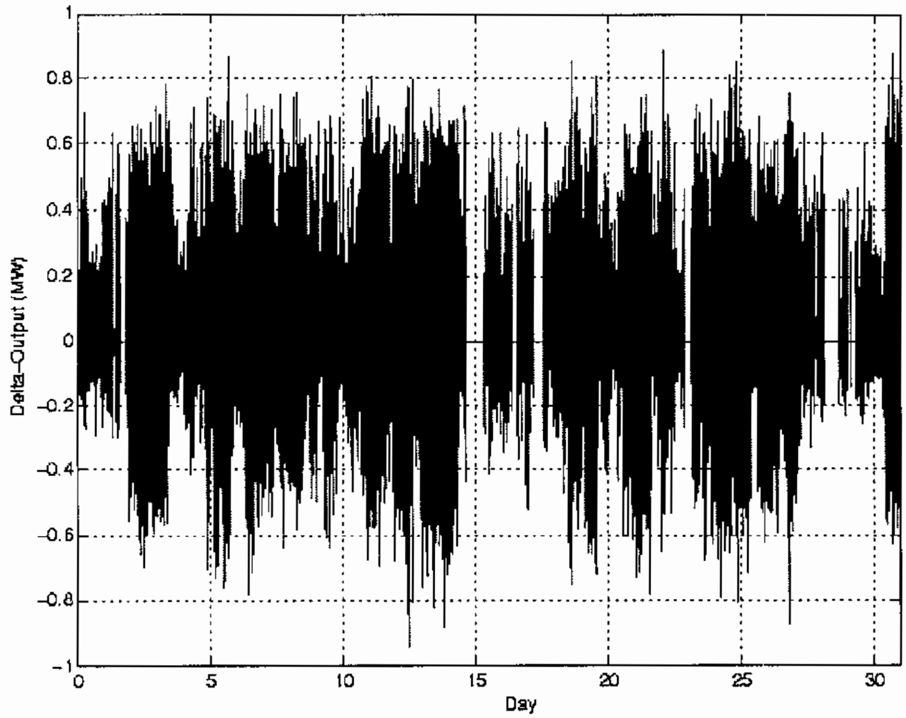

Figure 5.28 Second-to-second Change for One Month

The standard deviation of this entire sample is 0.0919 MW or about 0.1% of the farm rating. However, for any selected 10-minute sample, the standard deviation may be greater or less than this. Figure 5.29 shows a rolling 10-minute window of the standard deviation of the variation from Figure 5.28. There are very brief windows when the standard deviation reaches as high as 0.2 MW and periods when the variation is zero (corresponding to periods of no wind). The trend is around 0.1%, as expected. A histogram of these standard deviations is shown in Figure 5.30. The annotation on the figure points out the range of deviations for the 10-minute samples used for this study from Figure 5.26. The range of variance for the sample used to test New York State regulation in Section 6, *Operational Impacts*, is consistent with these field measurements.

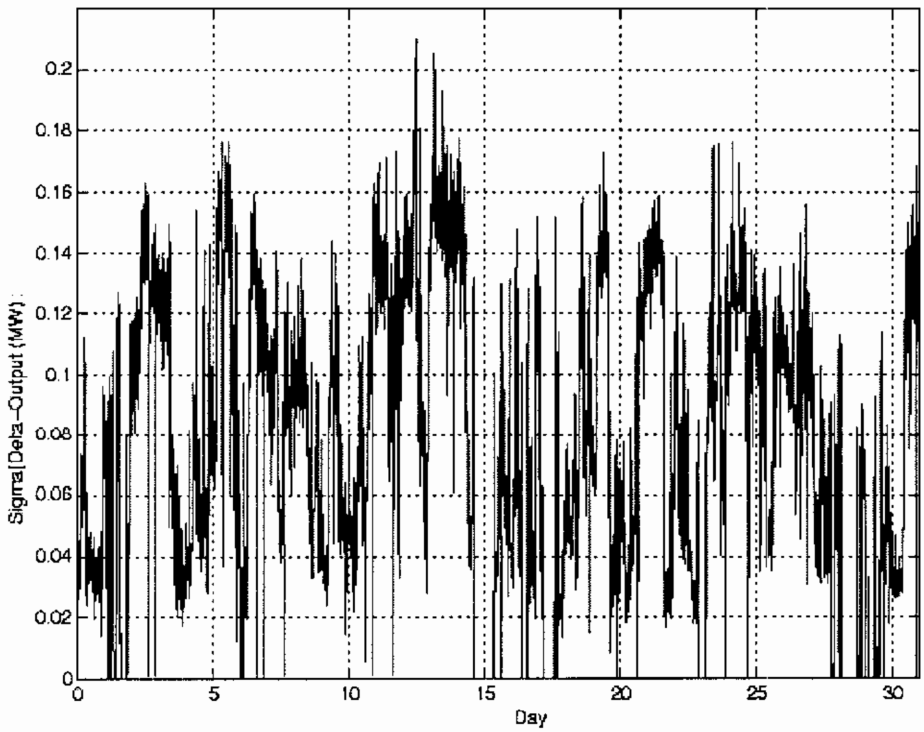

Figure 5.29 Rolling 10-minute Standard Deviation on One-second Change

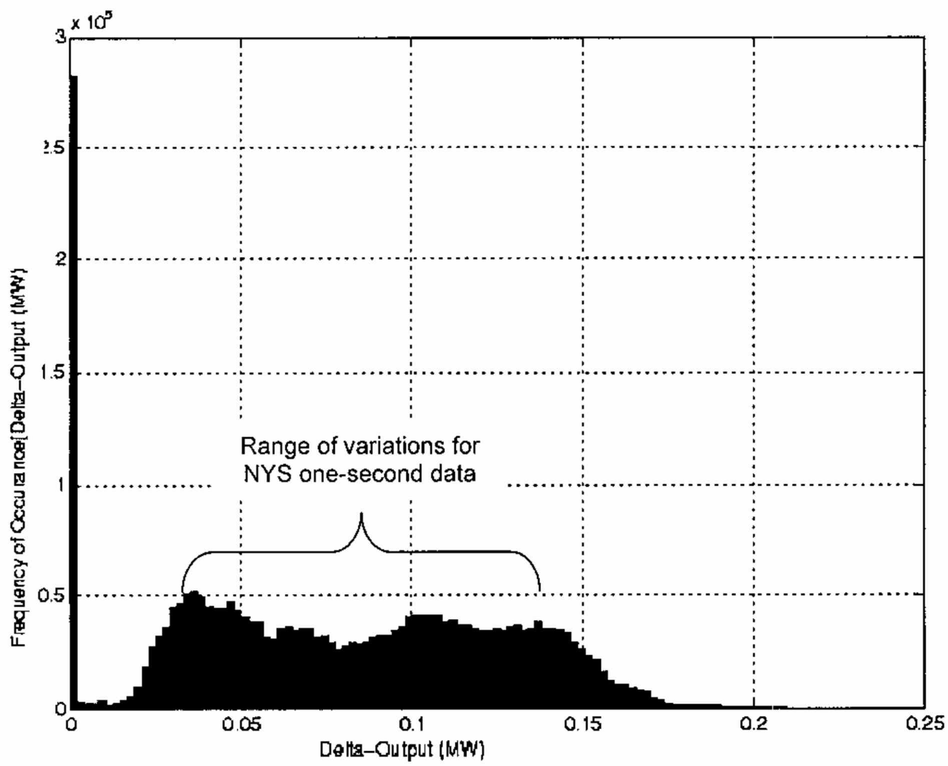

Figure 5.30 Histogram of Standard Deviation of One-second Change for Sliding 10-minute Window

5.4.3 Coincidence of Load and Wind Variability

For the six 10-minute, one-second resolution wind samples, there are three for which there are exactly corresponding New York State six-second load data sets (8/12/2003, 1/112003, and 4/17/2003). A histogram of the variance from the mean value of these 10-minute samples is shown in Figure 5.31. Similar histograms for the Superzone A-E and Zone K are shown in Figure 5.32 and Figure 5.33. The overall variation increases somewhat due to wind in each case. The statistics for these samples are summarized in Table 5.2. The most significant statistic is that the standard deviation at the state level increases by 12 MW from 71MW to 83 MW, which suggests that roughly 36 MW (3σ) increase in regulation capability would be required to maintain the same level of regulation compliance that New York State presently maintains. The present regulation of the NYSBPS exceeds minimum NERC criteria, so an increase in regulation capability is not expected to be required in order to meet minimum criteria with wind generation added to the system.

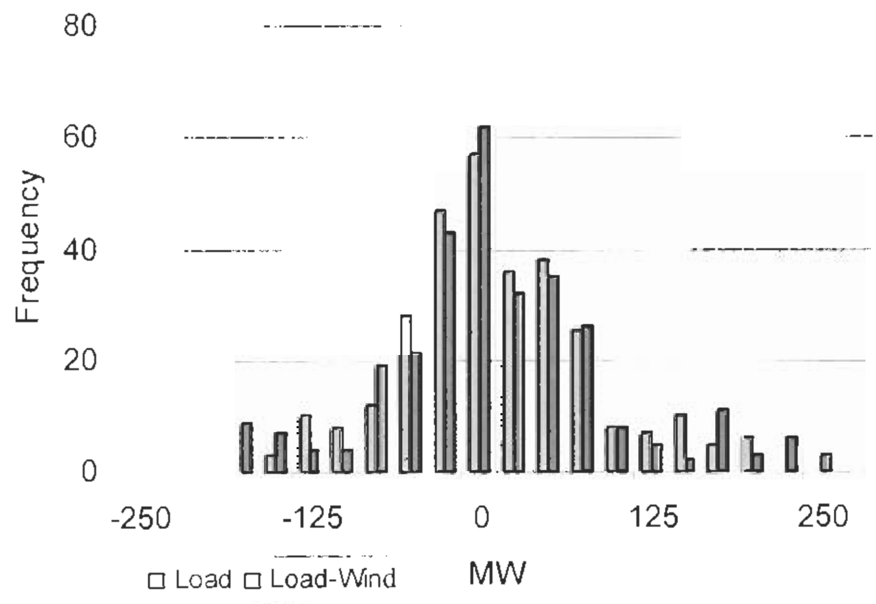

Figure 5.31 Histogram of Statewide 6-second Variance

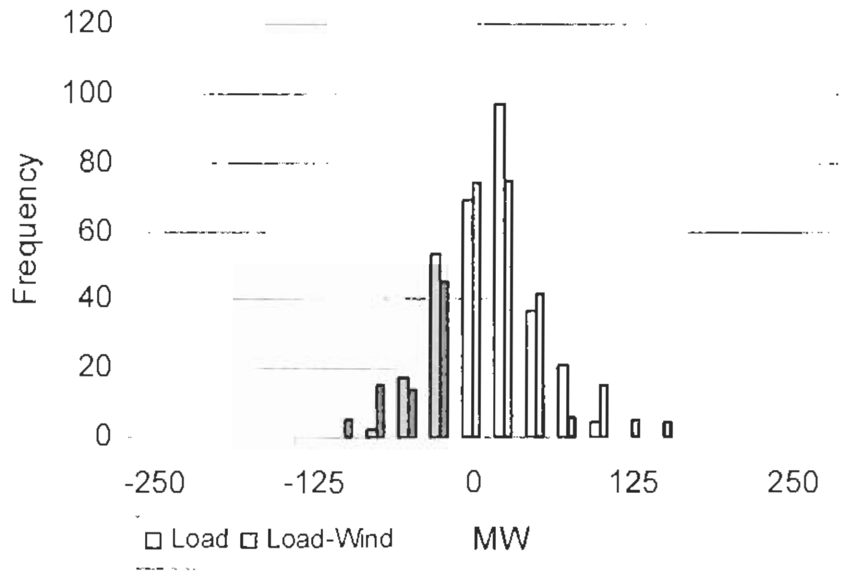

Figure 5.32 Histogram of Superzone A-E 6-second Variance

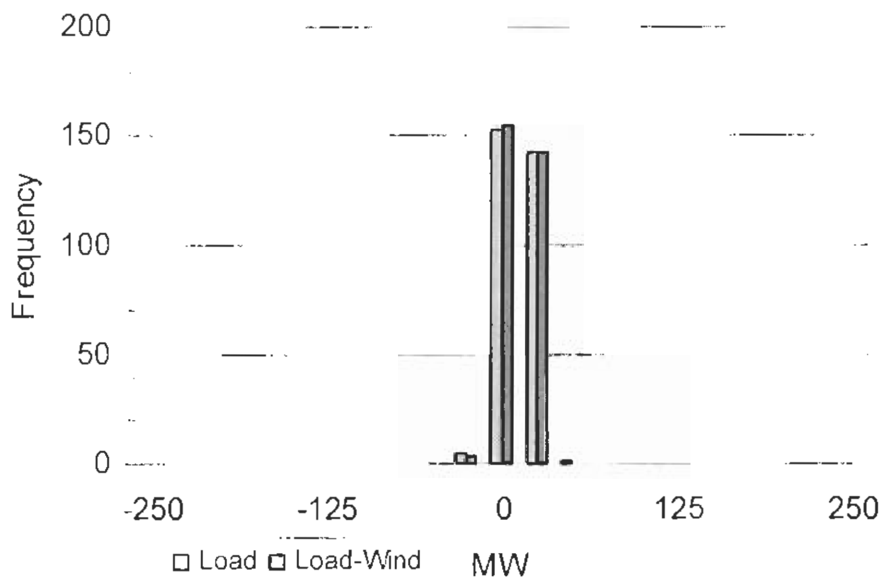

Figure 5.33 Histogram of Zone K 6-second Variance

Table 5.2 Statistics on six-second variability

	Zone K			Superzone			State		
Actual-Mean Delta	Load	Wind	Load-Wind	Load	Wind	Load-Wind	Load	Wind	Load-Wind
Mean	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Standard Error	0.63	0.24	0.63	1.91	0.97	2.72	4.08	0.96	4.78
Median	-0.68	-0.17	-1.05	1.20	0.06	-0.65	-10.11	-1.23	-8.22
Mode	0.90	-0.36	2.12	11.20	0.88	xx	26.12	-4.93	-48.39
Standard Deviation	10.88	4.14	10.90	33.09	16.84	47.18	70.71	16.59	82.75
Sample Variance	118.31	17.18	118.84	1,094.90	283.52	2,225.96	5,000.34	275.14	6,847.94
Kurtosis	0.05	1.02	-0.30	-0.20	1.99	0.70	0.38	0.89	0.94
Skewness	-0.04	0.11	0.01	0.18	-0.33	0.27	0.40	0.06	0.42
Range	58.00	22.80	53.62	169.00	99.37	258.70	350.00	88.26	435.52
Minimum	-32.68	-9.73	-29.74	-81.16	-55.35	-118.81	-156.27	-49.70	-192.09
Maximum	25.32	13.07	23.88	87.84	44.02	139.89	193.73	38.56	243.43
Sum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Count	300	300	300	300	300	300	300	300	300

5.5 Conclusions and Recommendations

5.5.1 Conclusions

There is a slight increase in variability for each time frame of operation, related to scheduling, load following and regulation.

The NYSBPS is expected to have the capability to respond to the increase in variability with existing practice and generating resources, with no significant impact on reliability.

A slight increase in regulation, on the order of 36 MW is required to meet the present level of CPS performance. No increase is necessary to meet minimum NERC requirements.

These conclusions are based on presumption of system and individual generators performing in adherence to operating rules.

The operational impacts of these variations are further quantified in Section 6, *Operational Impacts.*

5.5.2 Recommendations

No immediate changes in operations due to the variability impacts of wind are required.

NYISO should monitor potential impacts on load following and regulation as wind penetration increases; noting any performance issues, including failure of participants to adhere to operating rules.

6 Operational Impacts

The operational impacts of significant levels of wind generation cover a range of time scales. The annual, seasonal, daily and hourly impacts are described in Section 4, *Hourly Production Simulation Analysis*. The minute-to-minute or quasi-steady-state (QSS) and second-to-second or fundamental frequency stability impacts are described in this section. The QSS analysis evaluated 3-hour intervals under specific, time-variable load and wind conditions to determine the impact of wind on minute-to-minute changes to individual unit dispatch, in terms of load following and ramp rate requirements, as well as on the regulation requirements for units participating in automatic generation control (AGC). The stability analysis evaluated 1-second to 10-minute intervals to determine the impact of wind on system-wide transient stability performance, AGC performance, as well as the need, if any, for a variety of farm-level functions (e.g., voltage regulation, low-voltage ride through, etc). The selected QSS and stability time simulations are representative illustrations of system performance, and are intended to provide context to the statistical analysis presented in Section 5, *Wind and Load Variability.*

All analyses described in this section were performed using GE's PSLF (Positive Sequence Load Flow) and PSDS (Positive Sequence Dynamic Simulation) software package. Details of the QSS analysis are described in Section 6.1, *QSS Analysis*. The stability analysis is described in Section 6.2, *Stability Analysis*. Conclusions and recommendations are presented in Section 6.3, *Conclusions*.

6.1 QSS Analysis

The data, methods, tools, models, assumptions, study scenarios and results for the QSS analysis are described in the following subsections.

6.1.1 Approach

The objectives of the QSS analysis were to determine the impact of wind on 1) minute-to-minute changes to individual unit dispatch, in terms of load following and ramp rate requirements, as well as on 2) the regulation requirements for units participating in AGC and responding to changes in tie flows.

This was accomplished by performing a series of power flow solutions to simulate system performance on a minute-by-minute basis over selected 3-hour intervals. Each power flow in the series represented system conditions at a particular minute of the simulation. All loads varied from minute to minute. For simulations including wind generation, all wind farm power outputs varied from minute to minute. Finally, selected non-wind generating units were redispatched to accommodate the changes to load level or changes to both load level and wind generation.

Specifically, the following occurred in each QSS simulation at 1-minute intervals:

- all loads were modified according to a selected zonal load profile,
- all wind farm power outputs were modified according to a selected wind profile,
- all power required to balance total generation and load changes was assigned to a dummy generator acting as a proxy for all units on AGC.

The power output of the proxy unit approximated the amount of regulation required of all units on AGC between 5-minute redispatches of the system.

At 5-minute intervals, an additional operation was performed to emulate the economic dispatch of the system to follow load variations. The units that participate in the economic dispatch in a given study interval were redispatched with the objective of returning the AGC proxy unit output to near zero. Therefore, the following occurred every 5 minutes in each QSS simulation:

- all loads were modified according to a selected zonal load profile,
- all wind farm power outputs were modified according to a selected wind profile,
- all dispatchable units picked up a portion of the total change in load level and wind generation over the last 5 minutes, subject to individual ramp rate limits of 1% per minute,
- the impact of the application of the rate limits was identified as any dispatch requirements left over from the previous step,
- a second redispatch was performed to distribute that power among the units such that the load following is still achieved, but in a less economic manner,
- any remaining power required to balance total generation and load (i.e., maintain swing machine power output) was assigned to the AGC proxy generator.

The results of each 3-hour QSS simulation included zonal loads (MW), total New York State load (MW), zonal wind generation (MW), total New York State wind generation (MW), individual dispatchable unit power output (MW), selected internal interface flows (MW), tie flows between New York State and its neighbors (MW), impact of application of rate limits (MW), and dummy generator output (MW) as a proxy for all AGC units.

Additional details of the QSS analysis approach are discussed in the following subsections. The results are discussed in Section 6.1.2, *Results*.

6.1.1.1 Data

Four types of data were used in the QSS analysis: power flow databases, individual wind farm output profiles, zonal load profiles and MAPS hourly simulation results. Each is described below.

6.1.1.1.1 Power Flow Databases

NYISO provided three power flow databases for Phase I of this project, representing peak, light, and intermediate New York State load levels without significant wind generation. The same power flows were available for the QSS analysis. They represented the system conditions, i.e., total New York State generation and load, shown in Table 6.1. The QSS analysis was performed using the light load databases, since they best matched the study scenarios, as described in Section 6.1.1.2, *Study Scenarios*.

Table 6.1. Summary of QSS Power Flow System Conditions with No Wind Generation.

	Light Load	**Intermediate Load**	**Peak Load**
Total NY State Generation	14,514 MW	25,826 MW	32,525 MW
Total NY State Load	14,174 MW 5,797 MVAr	26,325 MW 10,873 MVAr	32,889 MW 13,597 MVAr

Power flows were also developed to represent the New York State system with the primary wind generation scenario, as described in the Section 1, *Introduction*. Thirty-seven individual wind farms were added to each of the above databases. Each wind farm was connected directly to a designated substation and represented by a single equivalent machine. The output of each wind farm was set by the selected wind profile. The total initial output from all 37 wind farms varied from about 500 MW to 2300 MW in this part of the study. The system redispatch required to accommodate wind generation followed the dispatch patterns observed in the MAPS simulations, as discussed in Section 6.1.1.1.4, *MAPS Simulation Results.*

6.1.1.1.2 Wind Profiles

AWS TrueWind provided individual wind farm output (MW) data for each of the sites included in the primary study scenario. Data with 1-minute resolution was used for the QSS analysis.

The 1-minute data included selected 3-hour intervals from different times of year and different periods of the day for a total of 108 potential wind events. Forty-five intervals represented typical wind farm output levels. Another forty-five intervals were similar but with higher levels of minute-to-minute variability. Eighteen intervals represented the largest observed changes in wind generation output, primarily due to the wind's diurnal cycle. A selection of the 1-minute data from each of the three categories is shown in Figure 6.1. Each trace represents the total New York State wind generation level (MW) for a specific 3-hour interval.

The 1-minute data was used as provided to set the wind farm output (MW) for each site during the QSS analysis. Additional information on the AWS TrueWind data is provided in Appendix A.

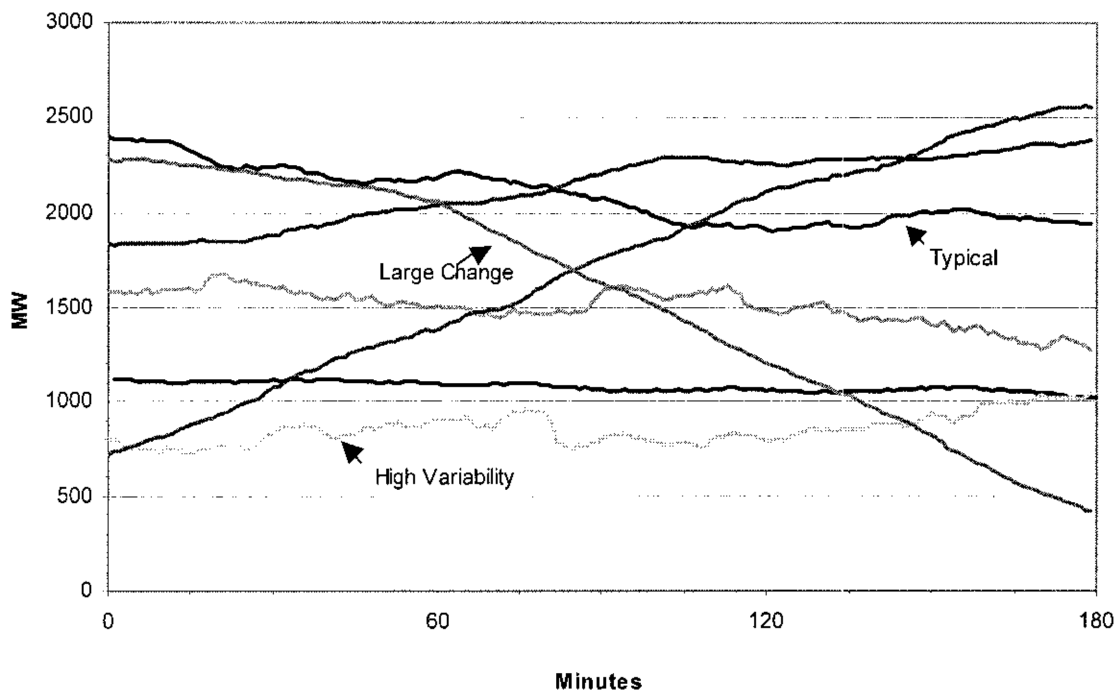

Figure 6.1. Total New York State Wind Generation (MW) over Selected 3-Hour Intervals.

6.1.1.1.3 Load Profiles

NYISO provided 6-second zonal load data (MW) for each day in January, April, August, and October 2003. An example for August 21, 2003 is shown in Figure 6.2. The black trace represents the total New York State load (MW, left scale). Each of the other lines represents a specific zonal load (MW, right scale) as identified in the legend. Some step changes in the data are observed, indicating either disturbances on the system or data anomalies. Study results were not affected by these anomalies.

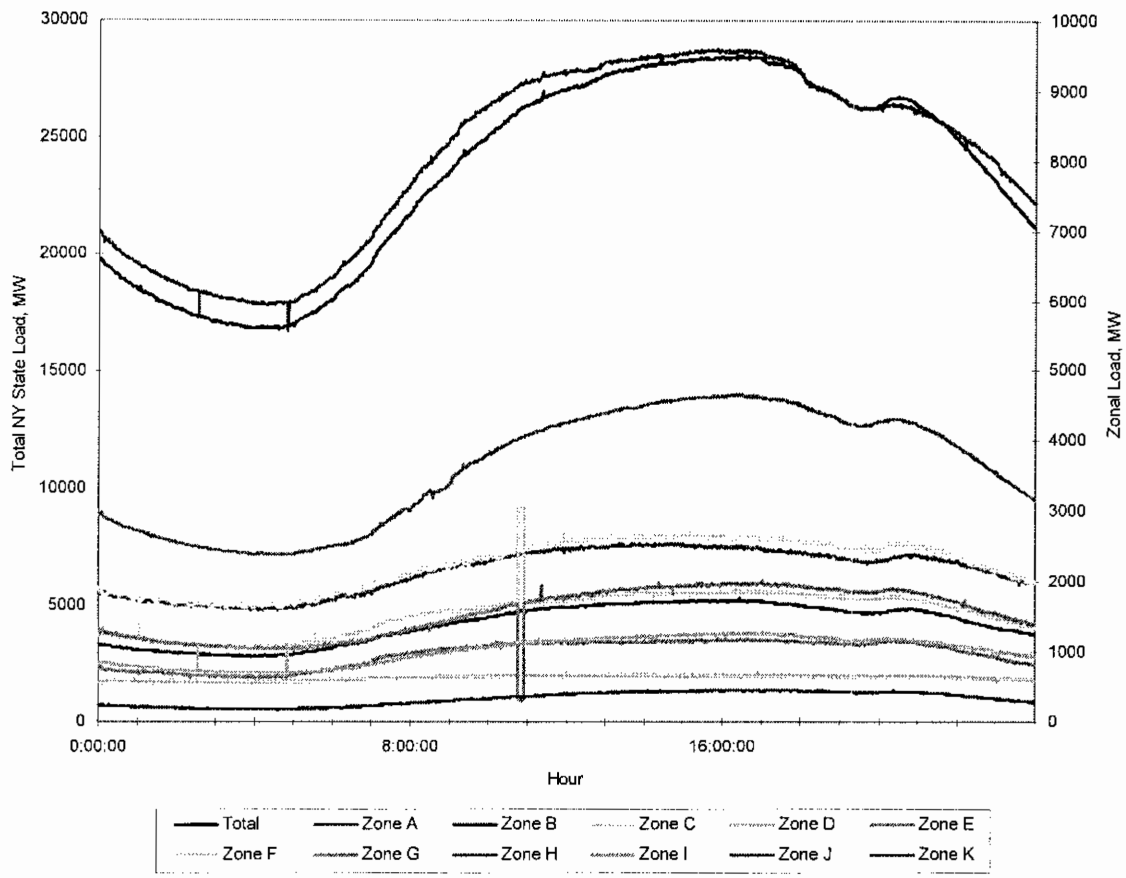

Figure 6.2. Example Load Profile from August 2003.

For the QSS analysis, the zonal load profiles were sampled every minute and then used to set the power level for all individual loads in New York State. Specifically, a change in zonal load from one minute to the next was spread across all loads in that zone, proportional to the size of an individual load.

6.1.1.1.4 MAPS Simulation Results

The results of MAPS simulations were used in the QSS analysis to 1) guide the system redispatch required to accommodate wind generation in the power flows, and 2) determine which units would be redispatched during a given 3-hour study interval to meet changes in load level or changes in both load level and wind generation. The MAPS simulations with wind assumed that the forecast was 100% accurate. That is, the schedule used for the commitment of the thermal generation assumed perfect foreknowledge of the wind generation. As a result, the minimum number of thermal units will be committed and therefore, available for load following. For the purposes of the QSS analysis, this represents a conservative assumption.

The MAPS simulations showed which non-wind generating units participated in load following over the study interval. Thus, dispatchable units are identified on an economic basis. Once these dispatchable units were identified, each was assigned a participation factor for the QSS analysis. The participation factor allotted some fraction of the redispatch requirements (MW) from one-minute to the next to a unit identified as dispatchable. The allotted fraction was proportional to the amount of redispatch observed on the unit in the MAPS results, compared to the total amount of redispatch required over a 3-hour interval. As an equation, the participation factor can be defined as follows:

$PF = MW_i/MW_{total}$

where: MW_i = MW change on i^{th} unit over 3-hour interval

MW_{total} = total MW change on all dispatchable units over 3-hour interval

Only the larger (over 50 MW) units in New York State were assigned a participation factor. Any scheduled changes in the output of small units which occurred over a given 3-hour interval were effectively added to the amount of redispatch required of the units with participation factors. Similarly, changes in tie flows between New York State and its neighbors were ignored. Therefore, any tie changes over a 3-hour study period were also effectively added to the amount of redispatch required of the New York units with participation factors. These are conservative assumptions, which require all of New York State's load following requirements to be met by New York generating units. In addition, the analysis focused on the *difference* between system performance (e.g., load following requirements) with and without wind generation. As a result, the absolute requirements were of secondary importance.

Details of the MAPS analysis are described in Section 4, *Hourly Production Simulation Analysis*.

6.1.1.2 Study Scenarios

The QSS study scenarios were selected to be severe, but likely, tests of the operational impacts of significant amounts of wind generation on New York State system performance. As noted in Section 7, *Effective Capacity*, the diurnal cycle of wind generation is generally opposite that of system load. For example, as load increases in the morning, wind generation decreases. Therefore, the analysis focused on large state-wide changes in wind generation paired with large state-wide changes in load level of the opposite sign.

The wind profile data, as provided by AWS TrueWind, was screened to identify the most stressful wind generation scenarios over a given 3-hour interval. The goals were as follows:

- Identify the largest state-wide increase in wind generation
- Identify the largest state-wide decrease in wind generation
- Identify the highest rate of increase in wind generation
- Identify the highest rate of decrease in wind generation
- Identify the highest level of minute-to-minute variability

Five wind profiles were selected, and are shown in Figure 6.3. The red line represents a September morning decrease in wind generation with the highest rate of change over a 15-minute period. The green line represents an August morning with the absolute largest decrease in wind generation over a 3-hour interval. The black line represents a May evening increase in wind generation with the highest rate of change over a 15-minute period. The blue line represents an October evening with the absolute largest increase in wind generation over a 3-hour interval. The pink line represents an April afternoon with little absolute change in wind generation but a high level of variability. Note that the largest statewide changes in wind generation coincided with the largest changes in wind generation across zones A through E. Therefore, one profile represents both the largest statewide changes as well as the largest Superzone A-E changes.

The majority of the wind generation was located in Superzone A-E, from 65% in the May wind scenario to 90% in the September wind scenario. This represented a penetration (Superzone A-E wind generation as a percent of Superzone A-E load) ranging from 10% in the October wind scenario to 40% in the August wind scenario. The above values represent system conditions at the beginning of a 3-hour interval.

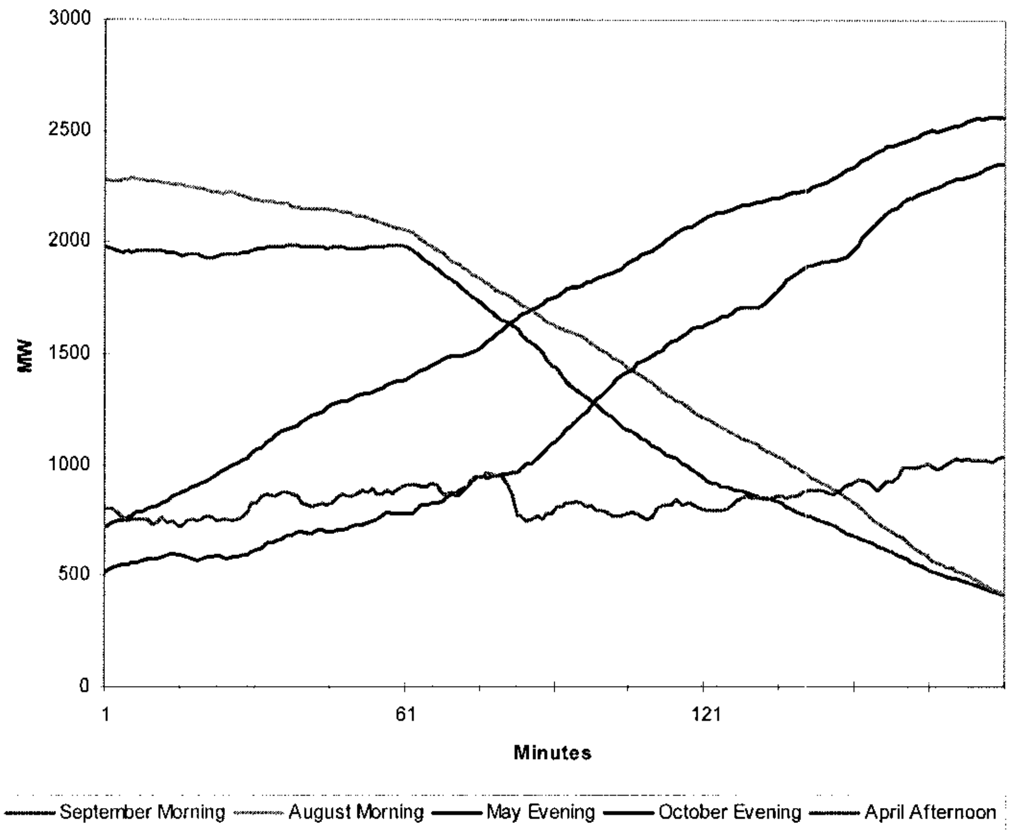

Figure 6.3. Wind Generation Study Scenarios.

Next, the load profiles, as provided by NYISO, were screened to identify 3-hour load intervals to pair with the selected wind generation scenarios. The goals were to identify 1) a large state-wide increase in load to pair with the decreasing wind generation scenarios, 2) a large state-wide decrease in load to pair with the increasing wind generation scenarios, and 3) a near-zero change in state-wide load to pair with the highly variable wind generation scenario. No exact time synchronization between the wind and load scenarios was possible. However, the time of year and time of day coincided. The wind and load scenarios selected for evaluation in the QSS analysis are shown in Figure 6.4. The solid lines represent the wind generation scenarios as shown in Figure 6.3, with the scale on the left. The dotted lines represent the selected load scenarios, with the scale on the right. The August morning load scenario (red dotted line) was paired with both the August and September morning wind generation scenarios. The October evening load (blue dotted line) was paired with the May and October evening wind generation scenarios. The April afternoon load scenario (pink dotted line) was paired with the April afternoon wind generation scenario.

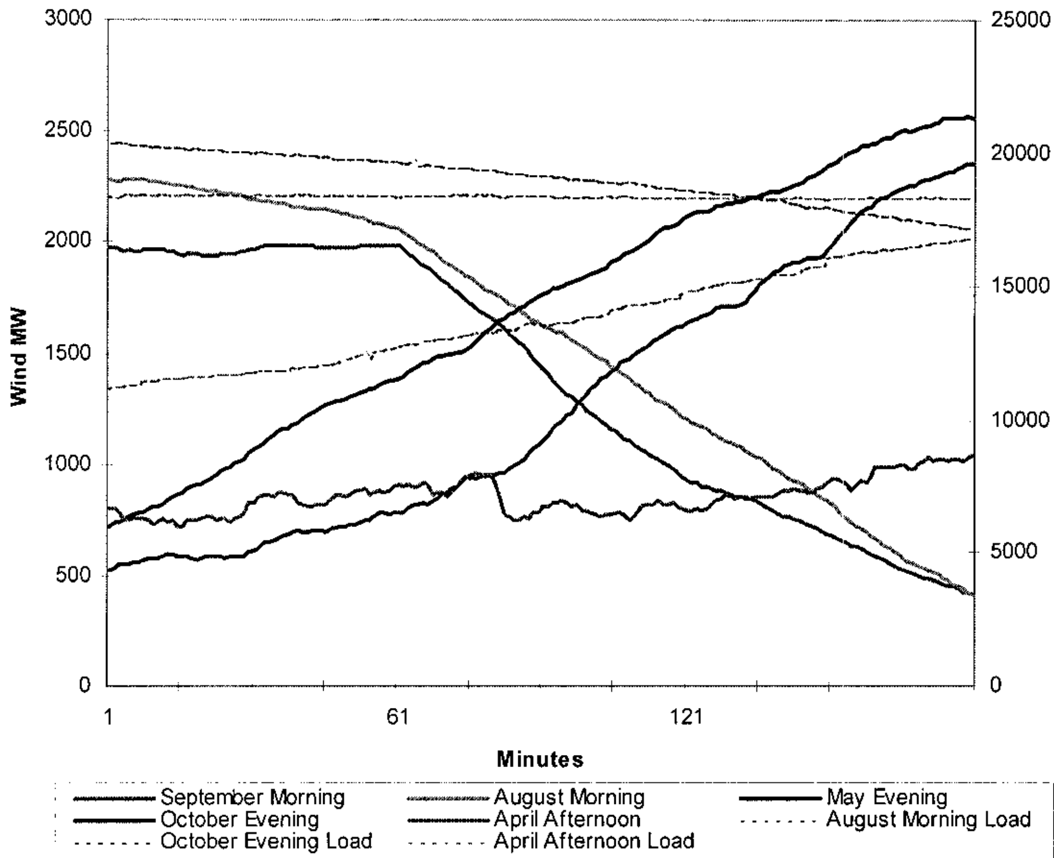

Figure 6.4. Wind and Load Study Scenarios.

A statistical analysis of wind and load variability was presented in Section 5, *Wind and Load Variability*. Figure 6.5 illustrates the relationship between a selected 3-hour QSS study scenario and that analysis. The distribution of hourly changes in summer morning load level is represented by the blue bar. The distribution of hourly changes, over the same time period, in both wind generation and load level is represented by the burgundy bar. The QSS August morning load scenario exhibits hourly changes from 1700 MW to 2100 MW. The combination of the August morning load and wind scenarios exhibits hourly changes from 2300 MW to 2700 MW. These ranges are also indicated in the figure.

A comparison of 5-minute changes from the running average is shown in Figure 6.6. The distribution of 5-minute changes due to load is represented by the blue bar, and the distribution due to the combination of wind generation and load level is represented by the burgundy bar. The QSS August morning load scenario exhibits 5-minute changes from 140 MW to 170 MW. The combination of the August morning load and wind scenarios exhibits 5-minute changes from 190

MW to 230 MW. These ranges are also indicated in the figure. Thus, the study scenarios represent severe tests of the impact of significant wind generation on system performance, in terms of both hourly and 5-minute variability.

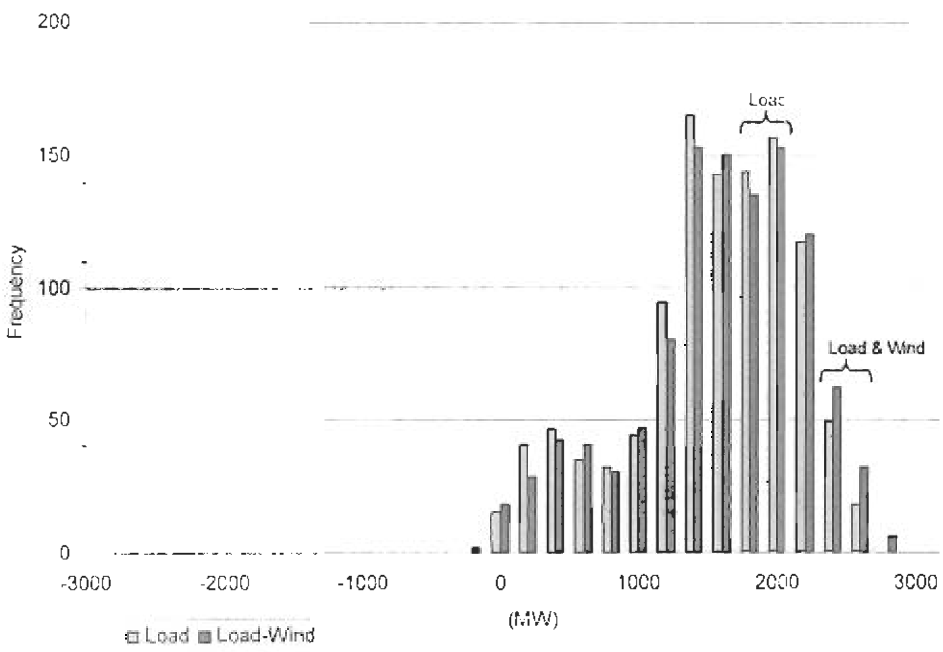

Figure 6.5. Distribution of Hourly Wind and Load Variations.

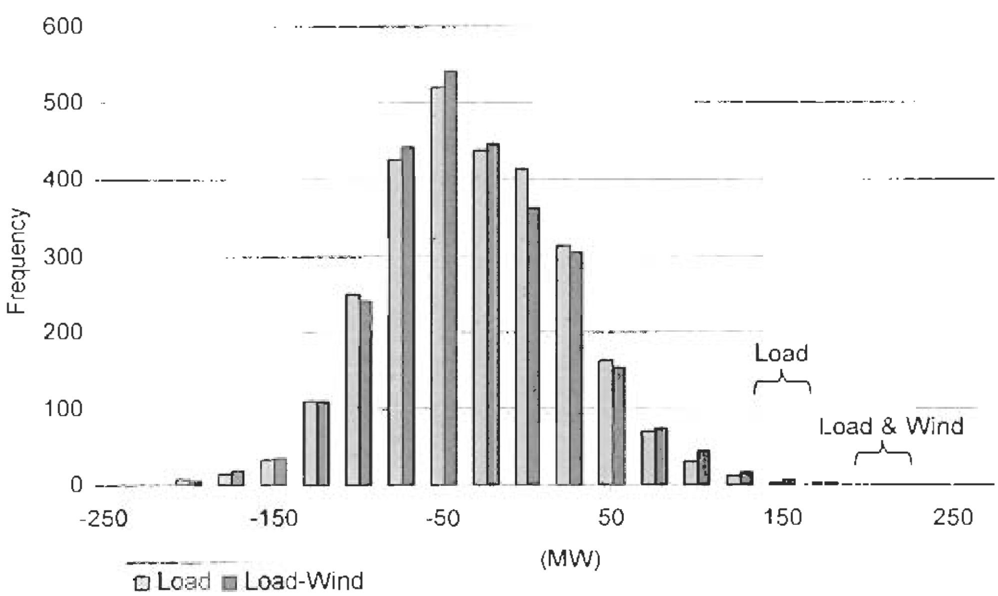

Figure 6.6. Distribution of 5-Minute Wind and Load Variations.

Finally, the non-wind generation units available for redispatch in a given 3-hour interval were identified from the MAPS simulation results, as described in Section 6.1.1.1.4, *MAPS Simulation Results*. Again, exact time synchronization was not possible. However, the time of year and time of day coincided. In addition, the MAPS results were selected such that the state-wide changes in wind and load in MAPS approximated the state-wide changes in wind and load as defined by the selected wind and load profiles.

A summary of the study scenarios is shown in Table 6.2. The change over a given 3-hour interval in total NYS load and total NYS wind generation, as well as the number of units participating in the load following, are shown in this table.

Table 6.2. Summary of QSS Study Scenarios.

Case	Δ NYS Load (MW)	Δ NYS Wind (MW)	# Δ Units
August Morning Load	5696	NA	60
August Morning Wind+Load	5696	-1861	65
September Morning Wind+Load	5696	-1561	65
October Evening Load	-3210	NA	19
May Evening Wind+Load	-3210	1837	29
October Evening Wind+Load	-3210	1834	29
April Afternoon Load	-45	NA	3
April Afternoon Wind+Load	-45	240	4

6.1.2 Results

The discussion of the QSS results is split into three subsections. Section 6.1.2.1, *Large-Scale Wind and Load Changes* discusses the impact of large changes in load level and wind generation on system performance. Section 6.1.2.2, *Wind Generation Variability* discusses the impact of minute-to-minute wind generation variability, and Section 6.1.2.3, *Active Power Control* reports on the impact of wind generation with an Active Power Control function.

6.1.2.1 Large-Scale Wind and Load Changes

The results of the first six study scenarios, as shown in Table 6.2, are discussed in this section. The impact of large decreases in wind generation, paired with large increases in system load level, are discussed in Section 6.1.2.1.1, *Wind Generation Drop/Load Level Rise Combination.* The impact of large increases in wind generation, paired with large decreases in system load level, are discussed in Section 6.1.2.1.2, *Wind Generation Rise/Load Level Drop Combination.*

6.1.2.1.1 Wind Generation Drop/Load Level Rise Combination

Selected results of the 3-hour QSS simulation with the August morning load profile, and no wind generation, are shown in Figure 6.7. The pink line represents the total New York State load (MW, left axis), the blue line represents AGC proxy unit output (MW, right axis), and the green line represents the impact of the application of rate limits (MW, right axis). Similar QSS results for the combination of the August morning load profile with the August and September wind profiles are shown in Figure 6.8 and Figure 6.9, respectively. In both figures, an additional light blue line represents total New York State wind generation (MW, left axis).

The results show two instances in which the application of ramp rate limits impacted the economic dispatch for the August load only scenario. The largest ramp rate impact was 7 MW. The largest impact of ramp rate limits was 4 MW and 5 MW for the August and September wind profiles, respectively. Note that more units were assigned to economic dispatch duty with wind, compared to the load only case, on the basis of the MAPS simulation results. Therefore, ramp rate limitations were reduced. Load following capability is not affected by the application of rate limits, but the units performing that duty may or may not be the most economic. In other words, there is no change in unit commitment, but some of the load following is performed by sub-economic units.

A cross plot of the AGC proxy unit output (MW), which approximates the regulation required between system redispatches, is shown in Figure 6.10 for the three cases. The blue line represents the August morning load only scenario, the solid red line represents the August wind scenario, and the dotted red line represents the September wind scenario. This plot illustrates the increase in regulation requirements due to the addition of wind generation.

The majority of peak values are in the range of 100 MW to 200 MW. The absolute peak was 273 MW for the August load only scenario. The absolute peak proxy AGC unit output with the August wind profile was 297 MW; the peak for the September wind profile was 353 MW. The increase for the September scenario coincided with the high rate of change observed near the midpoint of this wind profile. The average value of the peak AGC unit output was 125 MW, 163 MW, and 154 MW for the August load only, August wind, and September wind scenarios, respectively. These values are consistent with the 5-minute 3σ variation, 165 MW, calculated in Section 5.3, *Five-Minute Variability.*

A cross plot of the output of an example unit (MW) assigned to the economic dispatch is shown in Figure 6.11. The blue line represents the August morning load only scenario, the solid red line represents the August wind scenario, and the dotted red line represents the September wind scenario. Note that the QSS analysis only approximates real generating unit behavior. For example, real unit power outputs ramp smoothly between operating points. The stair step results of the QSS analysis approximate that behavior and illustrate key points. Specifically, the difference in initial operating point reflects the redispatch required to add wind generation to the system, and the difference in rate of increase in output indicates the increased load following requirements due to the addition of wind.

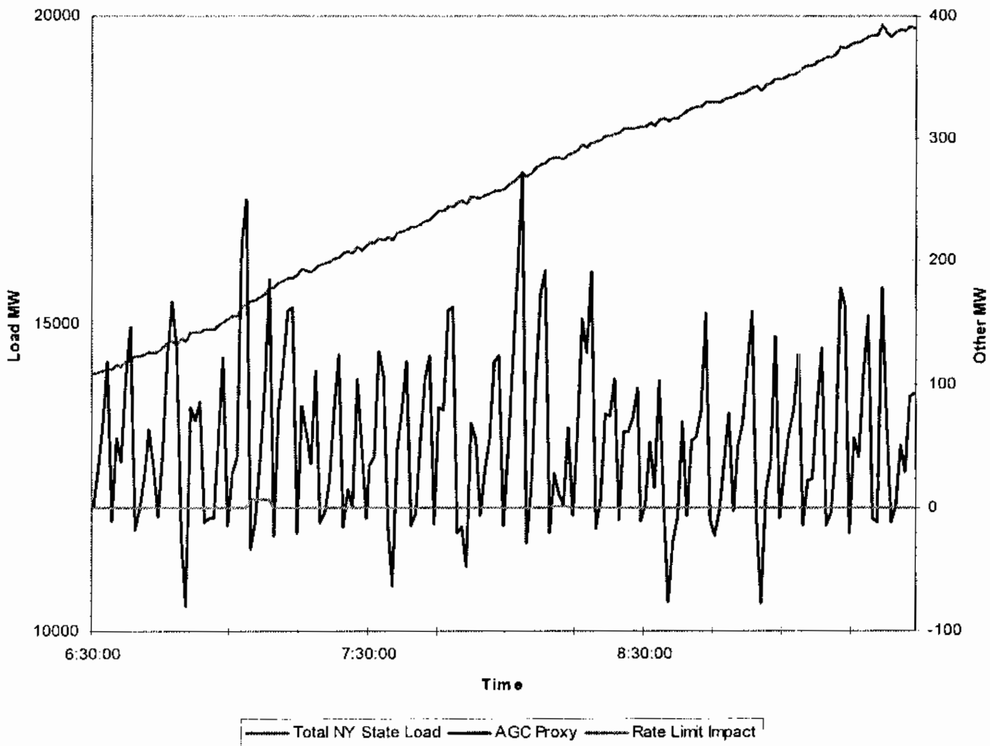

Figure 6.7. QSS Results for August Morning Load Rise, No Wind Generation.

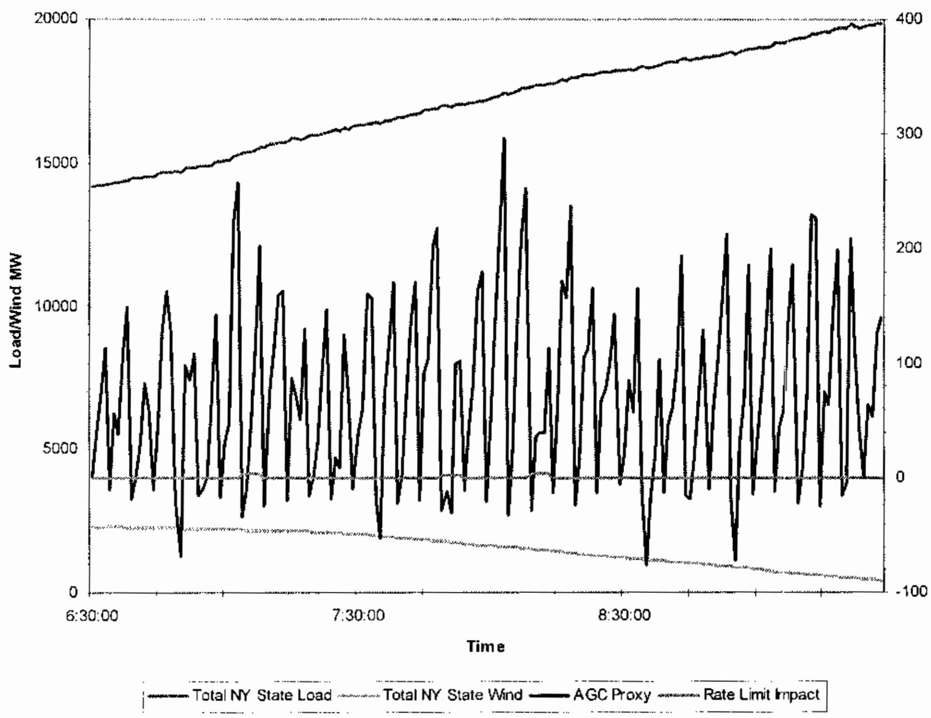

Figure 6.8. QSS Results for August Morning Load Rise, August Wind Generation Decrease.

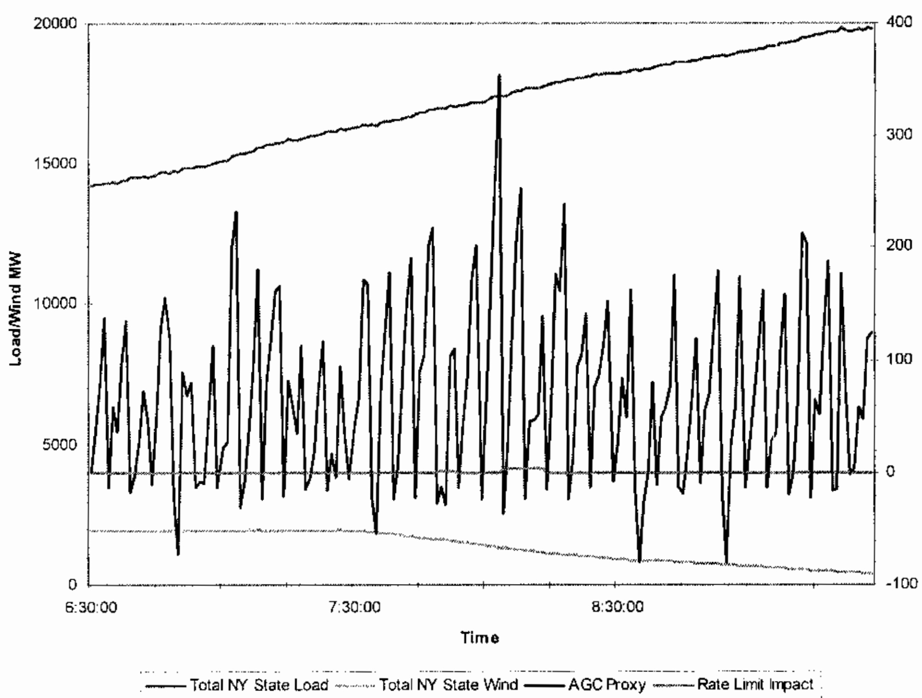

Figure 6.9. QSS Results for August Morning Load Rise, September Wind Generation Decrease.

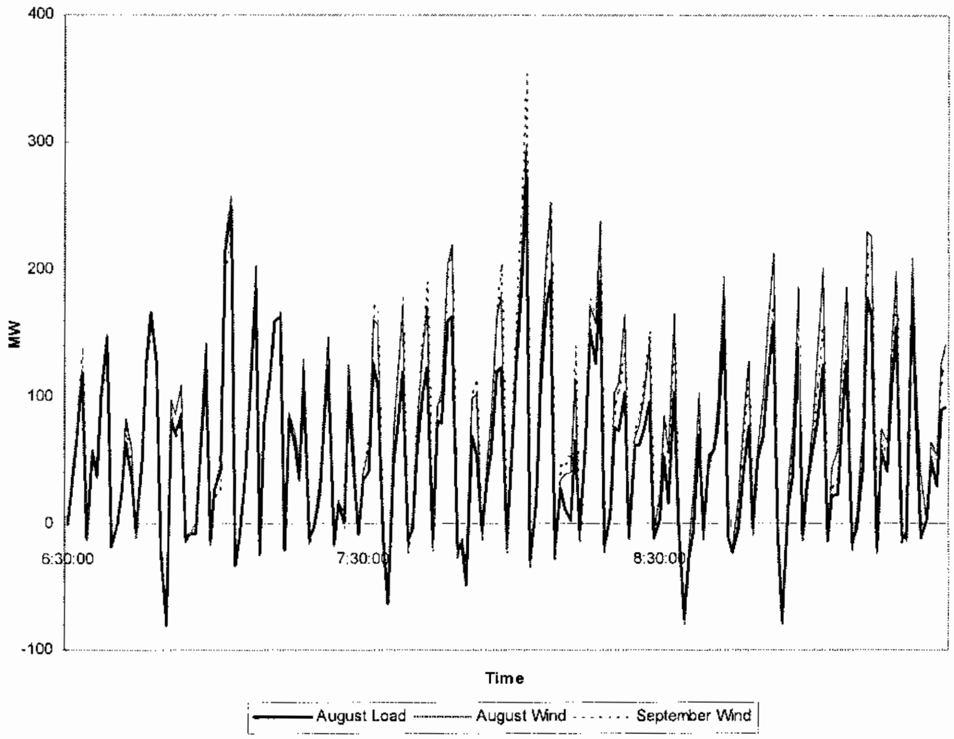

Figure 6.10. AGC Proxy Unit Output for August/September Study Scenarios.

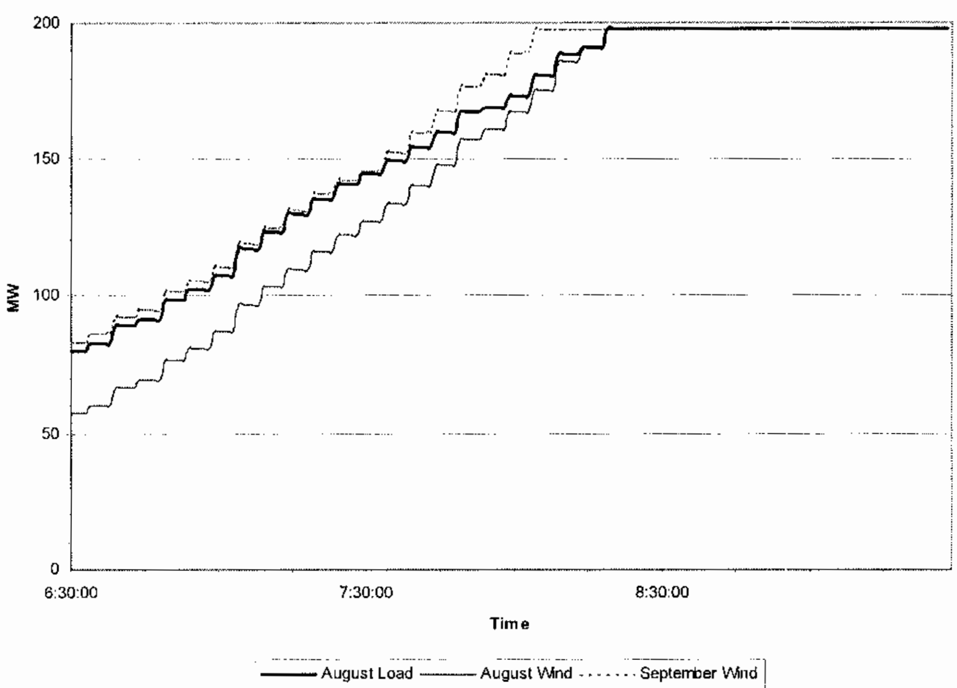

Figure 6.11. Example Unit Output for August/September Study Scenarios.

6.1.2.1.2 Wind Generation Rise/Load Level Drop Combination

A reduced set of plots are provided in the following discussion of the 3-hour QSS simulation of the October evening load profile, either alone or in combination with the October and May wind profiles.

A cross plot of the AGC proxy unit output (MW) for the three cases is shown in Figure 6.12. The blue line represents the October evening load only scenario, the solid red line represents the May wind scenario, and the dotted red line represents the October wind scenario. This plot illustrates the increase in regulation requirements due to the addition of wind generation. Note that the sign has changed from that observed in the August scenarios because the wind and load profiles have changed direction.

The majority of the minimum values are in the range of -50 MW to -150 MW. The absolute minimum was -210 MW for the October load only scenario. The absolute minimum proxy AGC unit output with the May wind profile was -260 MW; the minimum for the October wind profile was -315 MW. The increase for the October scenario coincided with a high rate of change observed in this wind profile. The average value of the peak AGC unit output was -78MW, -114 MW, and –114 MW for the October load only, October wind, and May wind scenarios, respectively. These values are consistent with the 5-minute 3σ variation, 165 MW, calculated in Section 5.3, *Five-Minute Variability.*

A cross plot of the impact of rate limits (MW) for the three cases is shown in Figure 6.13. The blue line represents the October evening load only scenario, the solid red line represents the May wind scenario, and the dotted red line represents the October wind scenario. Applying rate limits (1%/minute) had a more significant impact on these scenarios than on the August scenarios, since fewer units were assigned to the economic dispatch. Given the conservative assumptions in the assignment of units to dispatch duty, as outlined in Section 6.1.1.1.4, *MAPS Simulation Results*, the focus was on the difference between various cases not on the absolute results. Therefore, the sub-economic load following increased by approximately 9 MW for the May wind scenario and by about 24 MW for the October wind scenario. As noted before, this is not a change in unit commitment. Rather, some of the load following is performed by sub-economic units.

The amount of energy per hour redistributed from the most economic units to other less economic units is a quantitative measure of the amount of sub-economic load following. The energy per hour of sub-economic load following was 4.7 MWh/hr, 5.3 MWh/hr, and 4.2 MWh/hr for the

October load only, October wind, and May wind scenarios, respectively. The largest difference was observed for the October wind scenario, which resulted in a 0.6 MWh/hr increase in sub-economic load following.

The combination of decreasing load and increasing generation will not adversely impact system reliability. However, it will need to be accommodated by operations.

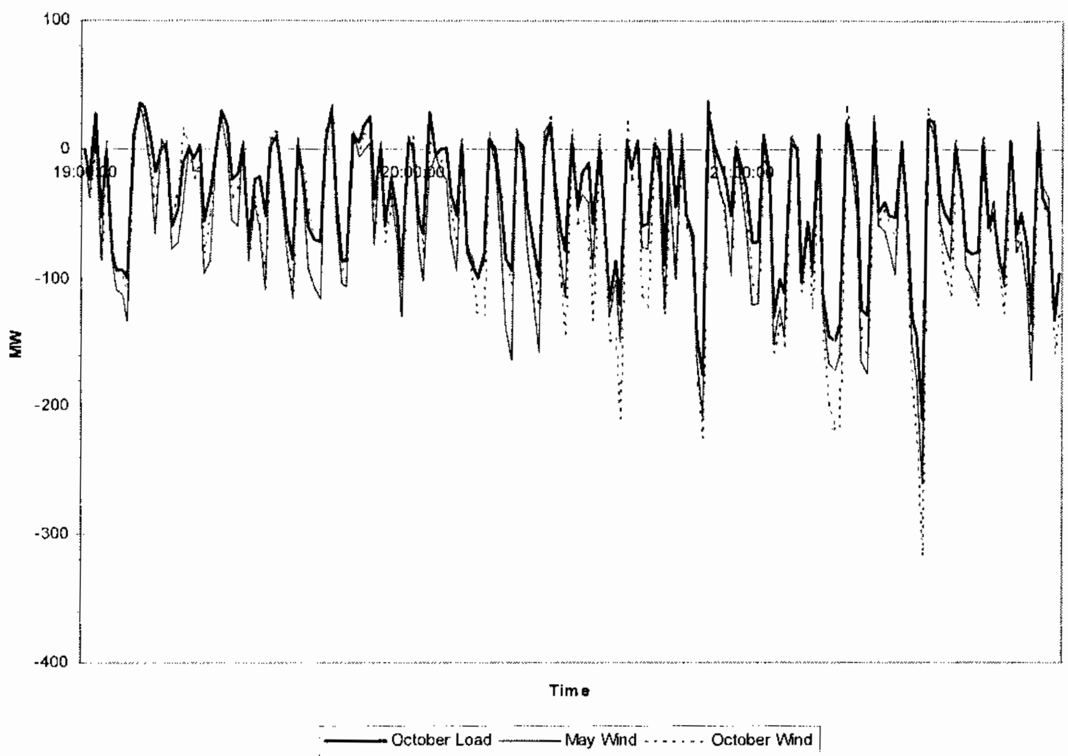

Figure 6.12. AGC Proxy Unit Output for May/October Study Scenarios.

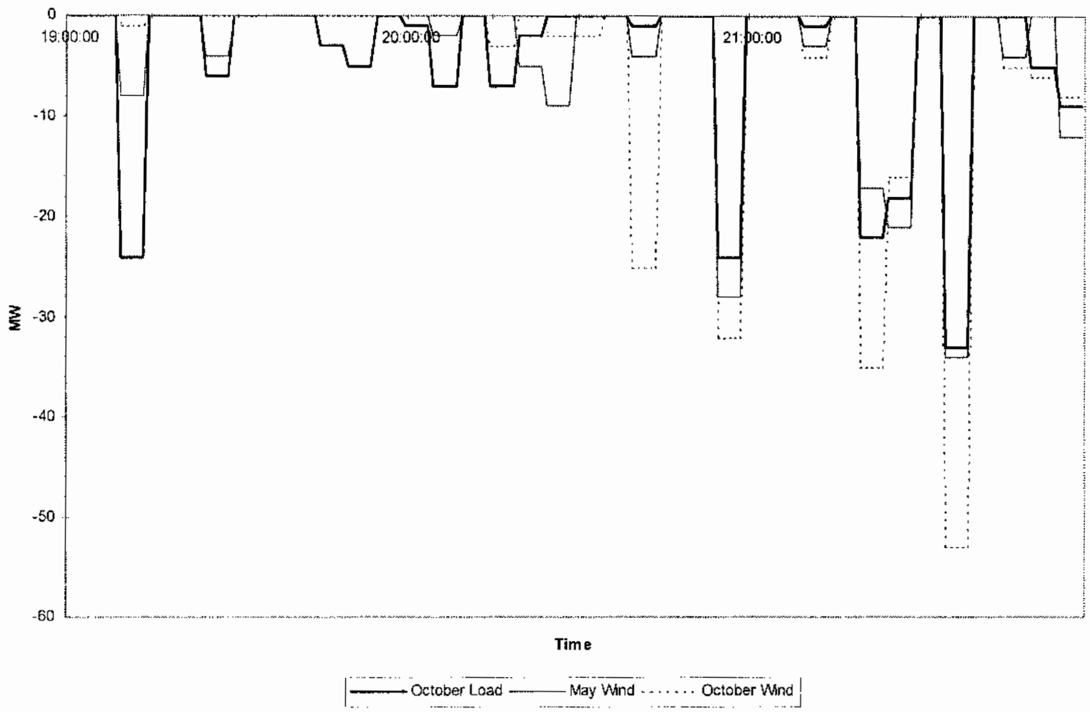

Figure 6.13. Rate Limit Impact for May/October Study Scenarios.

6.1.2.2 Wind Generation Variability

The results of the final two study scenarios, as shown in Table 6.2, are discussed in this section. The April load scenario was chosen for its relatively small changes over the 3-hour study interval. The April wind scenario was chosen for its relatively high minute-to-minute changes over the same interval.

Both the AGC proxy unit output and the impact of rate limits are shown in Figure 6.14. The solid blue line represents the proxy unit output (MW) for the April load only scenario, the dotted blue line represents the proxy unit output for the April wind scenario, the solid red line represents the impact of rate limits (MW) on the April load only scenario, and the dotted red line represents the impact of rate limits on the April wind scenario.

The average of the AGC proxy unit output hovers near zero, but this is not a meaningful measure of regulation needs with a nearly constant load. It is the dynamic range, from largest negative value to largest positive value, that is important. This range was 170 MW for the load only scenario, and 269 MW for the wind and load scenario. This additional regulation was required to achieve the same level of performance for the wind scenario. It also indicates that the regulation needs of the system may be higher than previously observed during some parts of the year.

However, the total regulating range requirement of 269 MW is consistent with current practice as described in Section 5.4.1, *AGC Performance*, and less than that observed for the August morning load only scenario. Hence, it can be met with modifications to the current processes.

A 60 MW increase in the sub-economic load following of the units on economic dispatch was also observed. Note that both scenarios used relatively few units (3 or 4) to perform the economic dispatch. Realistically, more units would be available to follow load. Nevertheless, this indicates that more load following may be needed during time periods when system load has historically been nearly constant.

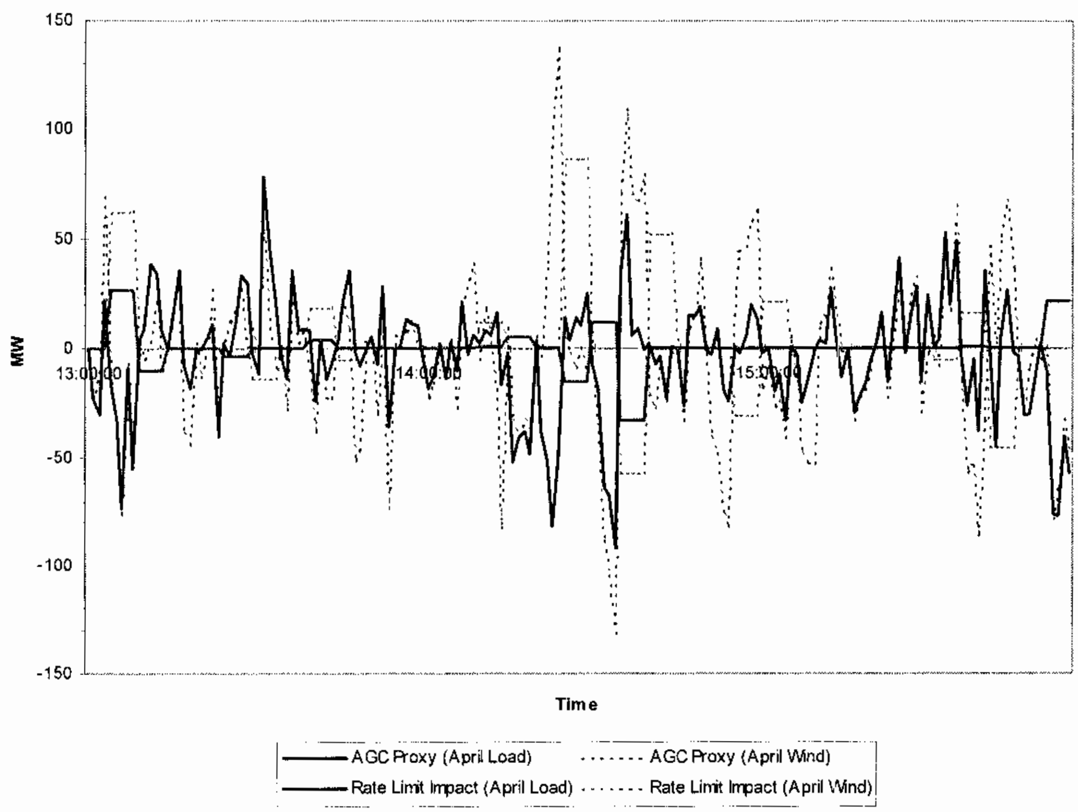

Figure 6.14. AGC Proxy Unit Output and Rate Limit Impact for April Study Scenarios.

6.1.2.3 Active Power Control

While active power control (APC) is not an industry-standard capability for wind turbine-generators, Phase I of this project recommended its future consideration. Therefore, the impact of one particular type of APC on system performance was evaluated. In general, an APC function could be used to reduce wind farm output to meet specific performance objectives. Note that it is uni-directional and cannot increase wind farm output above that associated with a given wind speed.

One type of APC was evaluated as part of the QSS analysis. This particular APC was a ramp rate limit, and constrained wind farm power output increases to no more than 1% of maximum output. The goal of such an APC would be to reduce wind generation variability, as well as to reduce the amount of regulation and load following required of other units.

Previous results, as described Section 6.1.2.1.2, *Wind Generation Rise/Load Level Drop Combination*, showed acceptable system performance with an unconstrained wind scenario. The aggressive (1%) ramp rate limit was selected to illustrate potential performance. It does not constitute a recommendation.

To test the APC, the October evening wind profiles were modified such that all wind farm outputs were subject to the 1% ramp rate limit on increases in generation, but not decreases. A comparison of an individual wind farm's output (MW) with and without APC is shown in Figure 6.15. The red line represents the original October evening wind profile for site 15. The blue line represents the modified wind profile for site 15, subject to the rate limits applied by the APC. A comparison of total New York state wind generation (MW) with and without APC is shown in Figure 6.16. Again, the red line represents the original wind profile and the blue line represents the wind profile as modified by the APC. The difference between the constrained and unconstrained wind generation profiles represents an adverse impact on energy production associated with a ramp rate limit function. For this example, the lost energy was approximately 6% of the total original energy. Therefore, such a function should only be used in specific applications to ensure system reliability.

A QSS simulation was performed using the above APC limited wind profile. A cross plot of the AGC proxy unit output (MW) is shown in Figure 6.17. The blue line represents the October evening load only scenario, the solid red line represents the original October wind scenario, and the dotted red line represents the APC limited October wind scenario. This plot illustrates the decrease in regulation requirements due to the APC. The majority of the minimum values are in the range of –50 MW to –150 MW. The absolute minimum was –210 MW for the October load only scenario. The absolute minimum proxy AGC unit output for the original October wind profile was –315 MW. The minimum value for the APC limited October wind profile was –270 MW, representing about 45 MW of improvement.

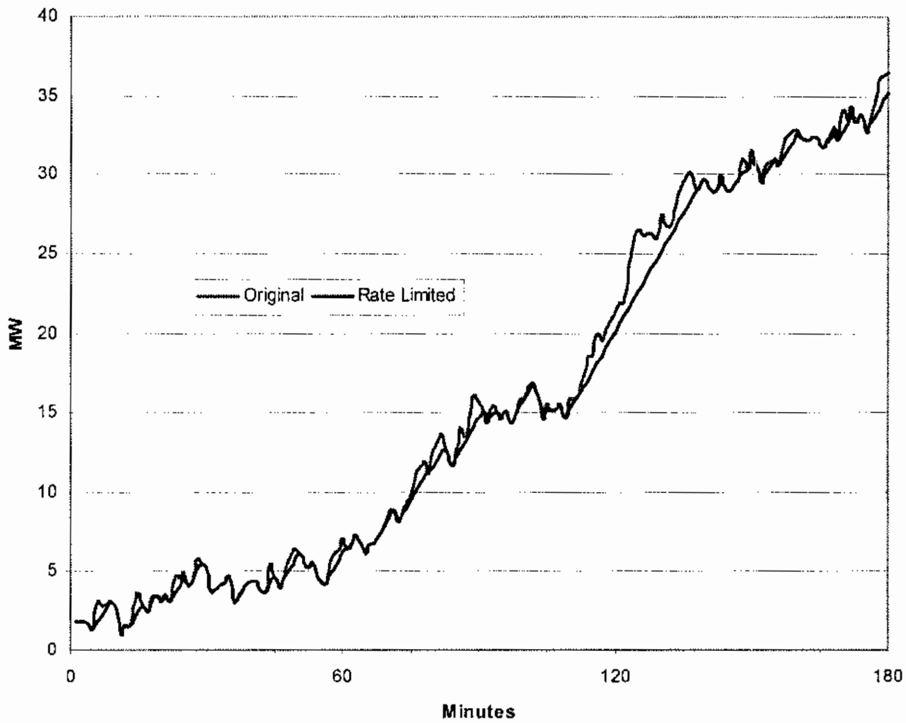

Figure 6.15. Individual Wind Farm Power Output with and without Active Power Control.

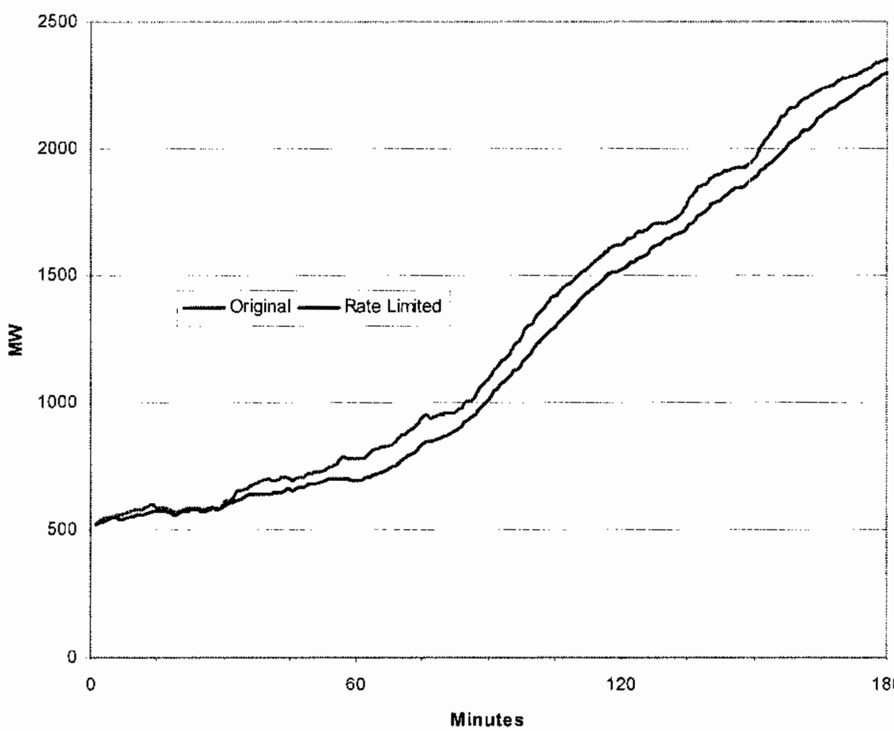

Figure 6.16. Total New York State Wind Generation with and without Active Power Control.

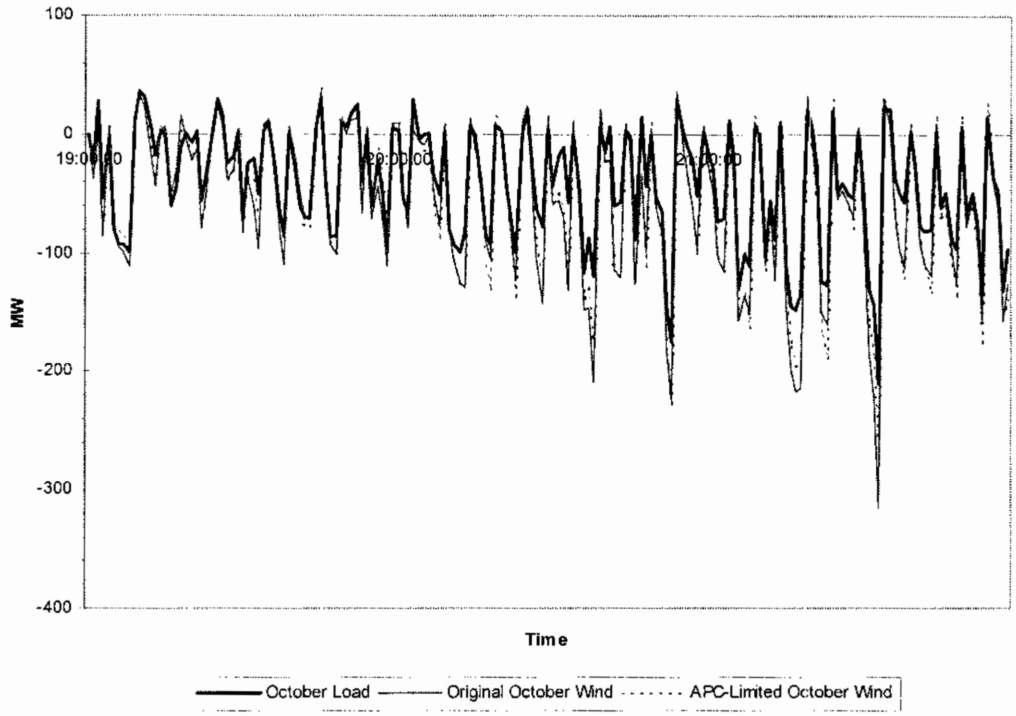

Figure 6.17. AGC Proxy Unit Output for October Study Scenarios with and without APC.

6.2 Stability Analysis

The data, methods, tools, models, assumptions, study scenarios and results for the stability analysis are described in the following subsections.

6.2.1 Approach

The objectives of the stability analysis were to identify the impact of significant wind generation on automatic generation control (AGC) performance, evaluate the impact of various farm-level functions (e.g., voltage regulation) and WTG technologies on system performance, and investigate system-wide transient stability performance. Therefore, two time frames of stability analysis were performed – long term (10-minute or 600 second) and traditional (10 seconds).

AGC performance was evaluated by applying selected 10-minute load or 10-minute load and wind generation profiles to the study system. The impact of wind farm voltage regulation was also evaluated in a 10-minute simulation.

Various farm-level functions (e.g., low voltage ride through), WTG technologies, and system-wide transient stability performance were evaluated in traditional 10-second stability simulations.

All New York generating unit, including all wind farm, variables were monitored in the stability analysis as well as selected internal interface flows, tie flows between New York State and its neighbors, and other case-dependent information.

Additional details of the stability analysis approach are discussed in the following subsections. The results are discussed in Section 6.2.2, *Results*.

6.2.1.1 Data

Three types of data were used in the stability analysis: power flow and dynamic databases, individual wind farm output profiles, and zonal load profiles. Each is described below.

6.2.1.1.1 Power Flow and Dynamic Databases

The three power flow databases provided by NYISO, representing peak, light, and intermediate New York State load levels without significant wind generation, were described in Section 6.1.1.1.1, *Power Flow Databases*. The light load case was used in the stability analysis, representing the system conditions shown in Table 6.3.

Table 6.3. Summary of Stability Power Flow System Conditions with No Wind Generation.

	Light Load
Total NY State Generation	14,514 MW
Total NY State Load	14,174 MW 5,797 MVAr

Power flows were also developed to represent the New York State system with the primary wind generation scenario, as described in Section 1, *Introduction*. Thirty-seven individual wind farms were added to each of the above databases. Each wind farm was connected via an appropriately sized transformer to a designated substation and represented by a single equivalent machine. The output of each wind farm was set by the selected wind profile. The total initial output from all 37 wind farms varied from about 600 MW to 2300 MW in the stability study. In general, the system redispatch required to accommodate wind generation was performed in the same zones in which the wind farms were added. This minimized the location-based impact of the wind generation and focused the evaluation on wind-specific issues, such as WTG performance, farm-level functions, etc.

Dynamic databases, corresponding to each power flow, were also provided by NYISO. These databases were augmented by the addition of an AGC model and WTG models, as needed. Unless otherwise noted, all WTG models were vector controlled, based on GE's 1.5MW WTG technology. All WTG models also included low voltage ride through (LVRT) capability sufficient to withstand 0.3pu voltage for up to 100 milliseconds, a reactive power output range of ± 0.436pu of maximum farm output, and voltage regulation. Remote (i.e., high side or transmission bus) regulation was implemented for all wind farms that did not share an interconnection bus. At transmission buses with multiple wind farm interconnections, local (i.e., low side or 34.5kV collector bus) regulation was implemented. Details of the dynamic WTG models are provided in Appendix D. Details of other dynamic models (e.g., AGC) are provided in Appendix E.

6.2.1.1.2 Wind Profiles

In addition to the 1-minute data used in the QSS analysis, AWS TrueWind also provided 1-second data for the stability analysis. A statistical analysis of that data is provided in Section 5.4.2, *One-Second Wind Variability.*

The 1-second data included six selected 10-minute intervals from different months and different times of day. Again, the data was provided in terms of power output (MW) by individual site. However, the wind turbine-generator (WTG) model used in the stability analysis requires wind speed as its input variable. Therefore, the power output data (MW) was converted to wind speed (m/s). To test the accuracy of the conversion, the calculated wind speed was used to drive a simulation and the resulting wind farm power output was compared to the original AWS TrueWind data. An example of this comparison is shown in Figure 6.18. The green trace represents the AWS power output (MW) data and the pink trace represents the power output (MW) resulting from a simulation using calculated wind speed as an input signal. The largest difference between input data and simulated results was approximately 0.5MW. This level of accuracy was deemed acceptable. Therefore, calculated wind speed was used as the input signal for the equivalent WTGs in the stability analysis.

As noted above, the data was provided with 1-second resolution. However, stability simulations use time steps on the order of 4 milliseconds. Therefore, a simple interpolation was performed to generate wind speeds between each 1-second data point.

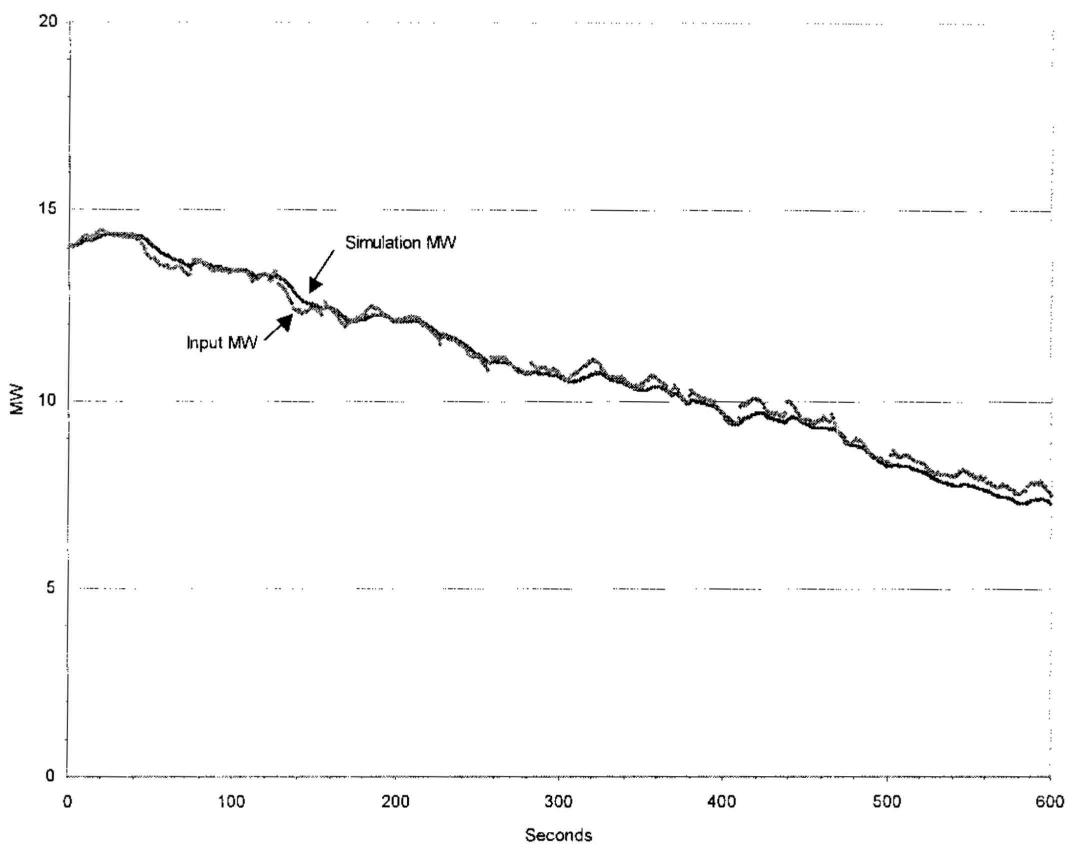

Figure 6.18. Wind Farm Power Output Comparison.

Additional information on the AWS TrueWind data is provided in Appendix A. Additional information on the wind turbine-generator model is provided in Appendix D.

6.2.1.1.3 Load Profiles

NYISO provided 6-second zonal load data (MW) for each day in January, April, August, and October 2003, as described in Section 6.1.1.1.3, *Load Profiles*.

The zonal load profiles were used to set the power level for all individual loads in New York State in the stability analysis. Specifically, a change in zonal load from one data point to the next was spread across all loads in that zone, proportional to the size of an individual load. In addition, a simple interpolation was performed to generate load levels between each 6-second data point.

6.2.1.2 Study Scenarios

The evaluation of AGC performance was performed on the light load database, using 10 minutes of 6-second load and 1-second wind profiles. The studied load (MW, blue line) and wind generation (MW, red line) profiles are shown in Figure 6.19. They represent part of an August morning with a total New York State 10-minute load increase of approximately 250 MW, and a total wind generation 10-minute decrease of approximately 150 MW. As the QSS analysis evaluated system performance for wind and load profiles with opposing trends, so did this part of the stability analysis. The same load and wind profiles were used in the evaluation of the impact of voltage regulation on system performance.

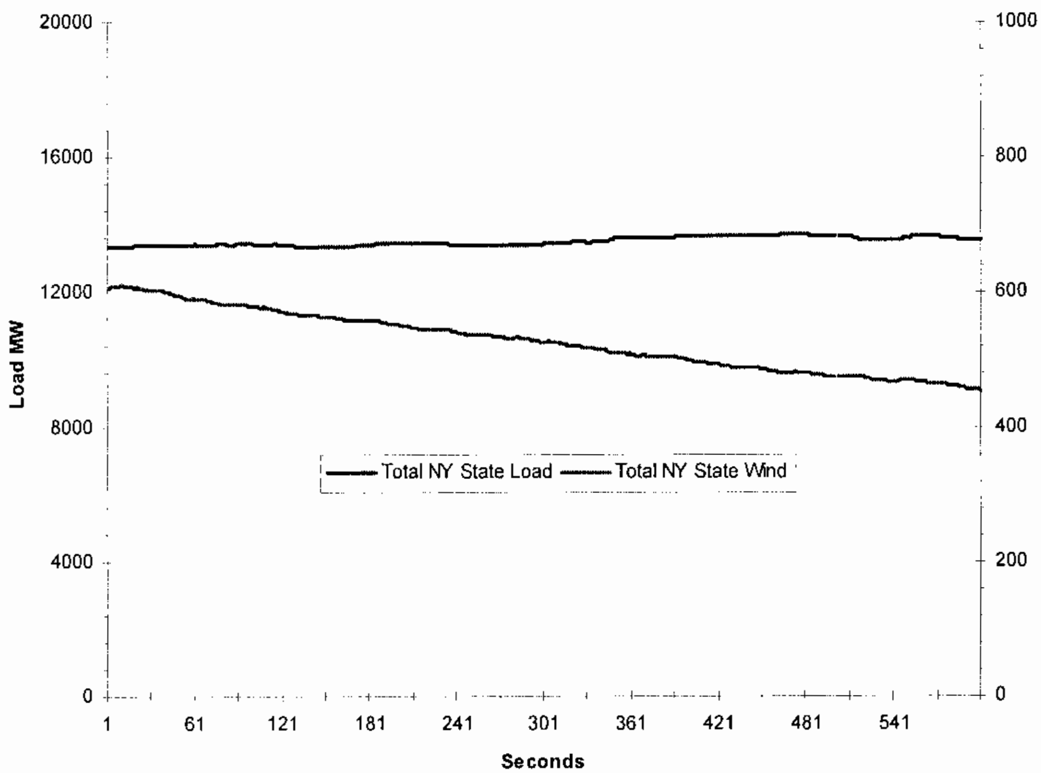

Figure 6.19. Wind and Load Profiles for 10-minute Stability Simulations.

The evaluation of other farm-level functions (e.g., LVRT), WTG technologies, and system-wide transient stability was also performed on the light load database, using a 3-phase Marcy 765kV fault and line clearing event as the test disturbance. The load levels and wind farm output levels were not modified during the course of these simulations.

6.2.2 Results

The discussion of the stability results is split into two subsections. Section 6.2.2.1, *Wind Farm Performance*, discusses the impact of various farm-level functions on system performance in the 1 to 10-second time frame, and Section 6.2.2.2, *System Performance*, discusses the impact of wind generation on overall system performance in the 10-minute time frame.

6.2.2.1 Wind Farm Performance

The impact of low voltage ride through (LVRT) capability, voltage regulation, and wind turbine generator technology differences on system performance are described in the following sections. The ability of wind farms to withstand frequency swings is also evaluated.

6.2.2.1.1 Overall Stability Performance

The transient stability behavior of wind generation is significantly different from conventional synchronous generation. The distinction is particularly acute for vector controlled wind turbine-generators[xii]. Like conventional generators, wind turbine-generators will accelerate during system faults. However, unlike synchronous machines there is no physically fixed internal angle that must be respected in order to maintain synchronism with the grid, and which dictates the instantaneous power delivered by the machine to the grid. With WTGs, the internal angle is a function of the machine characteristics and controls, allowing a smooth and non-oscillatory re-establishment of power delivery following disturbances. The difference in behavior is similar to that of a automobile shock absorber: the WTG will respond to system events (potholes), but not rigidly transmit the effect of a disturbance between the turbine (passengers) and grid (road). These same characteristics also mean that WTGs will not contribute to system oscillations. The net result of this behavior is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation.

To illustrate the difference, selected results of two Marcy fault simulations are shown in Figure 6.20. Specifically, the Marcy 345kV bus voltage (pu) and Total East interface flow (MW) are shown. The solid line represents a case with the 37 wind farms in-service, generating approximately 2280 MW. The dotted line represents system performance with no wind generation. Both the post-fault voltage dip and the oscillations in the interface flow are improved with the addition of vector controlled WTGs.

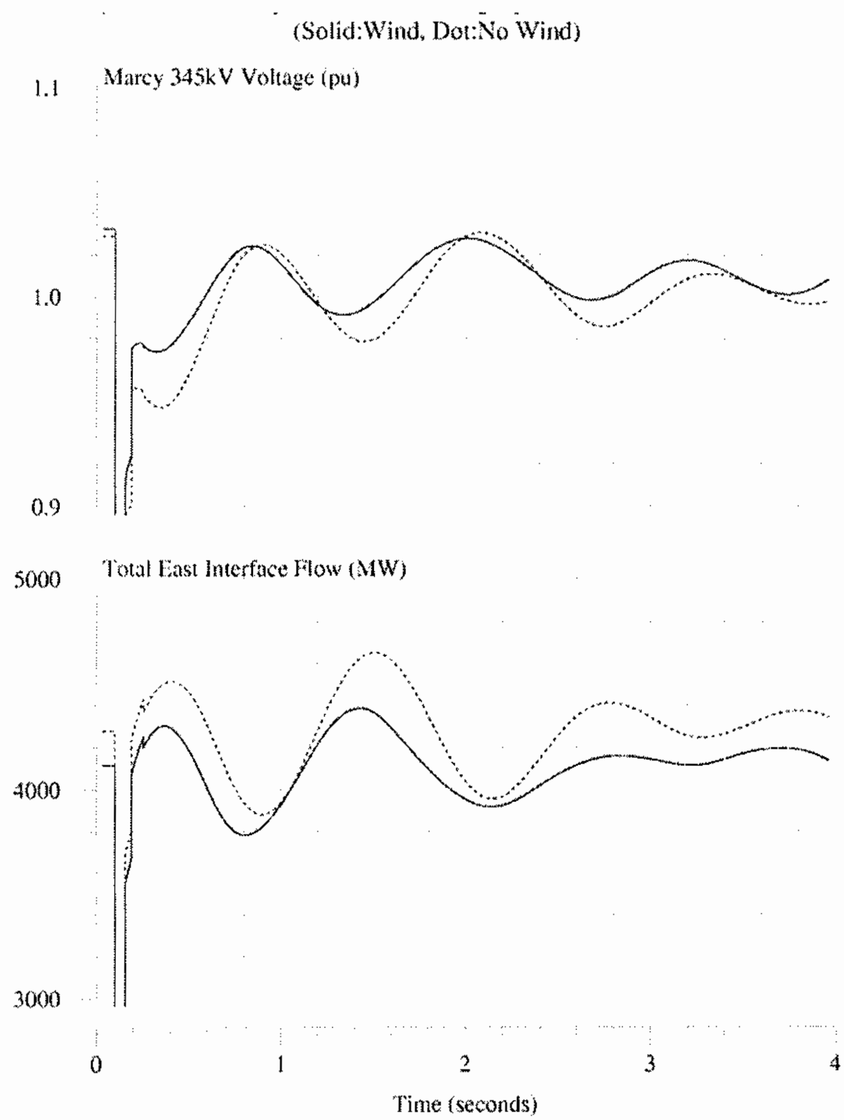

Figure 6.20. Impact of Wind Generation on System Performance.

6.2.2.1.2 Low Voltage Ride Through (LVRT)

Historically, the utility industry expected wind generation to trip in response to significant system disturbances. This expectation, and often requirement, was driven by the fact that wind generation constituted a small portion of the total generation resource pool, and most wind generation was sprinkled throughout distribution systems. These considerations are no longer applicable. Both the penetration of wind generation and the size of wind farms connected directly to the transmission grid have increased. In turn, a utility's exposure to significant simultaneous loss of wind generation in response to low voltages has also increased. Therefore, the ability of WTGs to tolerate momentary depressions in system voltage due to system faults is of significant concern to the utility industry. This capability is variously called "fault ride-through," "low voltage ride-through" (LVRT), and "emergency voltage tolerance". Therefore, the impact of LVRT on both system and farm-level performance was evaluated in this study.

As noted in Section 6.2.1.1.1, *Power Flow and Dynamic Databases*, the selected LVRT function allowed WTGs to withstand a 0.3pu voltage for up to 100 milliseconds. Note that the industry is moving toward a more aggressive LVRT requirement in terms of both minimum voltage and timer thresholds.

Selected results of two Marcy fault simulations are shown in Figure 6.21. Specifically, the Marcy 345kV bus voltage (pu), Total East interface flow (MW), and Site 6 wind farm power output (MW) are shown. The solid line represents a case with the 37 wind farms in-service, generating approximately 2280 MW, with LVRT capability on all farms. The dotted line represents the same wind generation scenario but without LVRT capability. There is no significant difference in system-wide voltage or interface flow performance with or without LVRT capability.

However, it can be observed that without LVRT, the wind farm trips when the interconnection bus voltage dips below 0.7pu, resulting in a loss to the system of approximately 300MW of generation. With LVRT, this wind farm remains connected to the system. NYS performance criteria do not allow tripping of remote generation for design criteria faults. Only local generation that is included in the fault may trip.

In addition, the loss of generation associated with the lack of LVRT could be significant under severely stressed system conditions or in response to more severe fault disturbances. The distribution of terminal voltages observed at each wind farm in response to the Marcy fault is shown in Figure 6.22. The blue dots represent the minimum terminal voltages at each site. The red line shows the voltage tripping threshold (0.7pu) for WTGs without LVRT and the yellow line shows the voltage tripping threshold (0.3pu) for WTGs with the LVRT used in this analysis. Note that Sites 6 and 25 are the only two sites with low enough voltages to trip without LVRT. The green line represents the voltage tripping threshold (0.15pu) which appears to be the consensus emerging from on-going industry-wide discussions. It is recommended that NYS adopt the emerging LVRT specification.

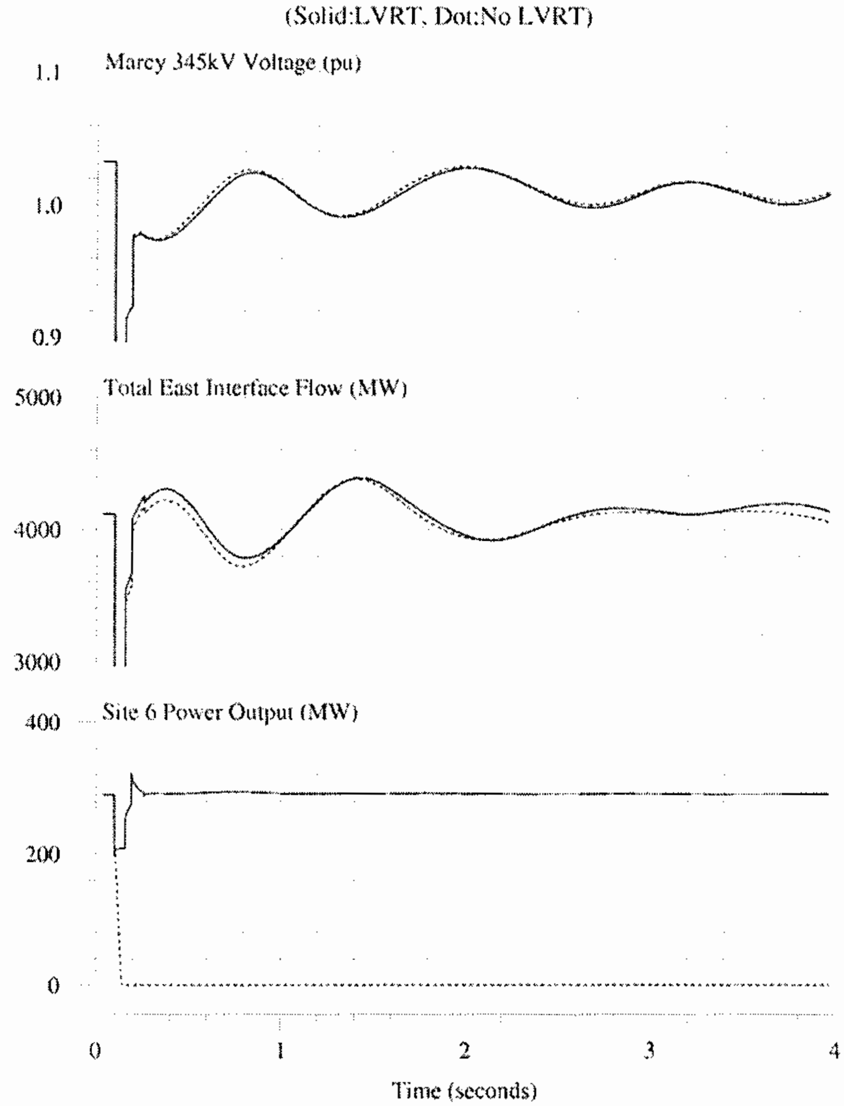

Figure 6.21. Impact of LVRT on System Performance.

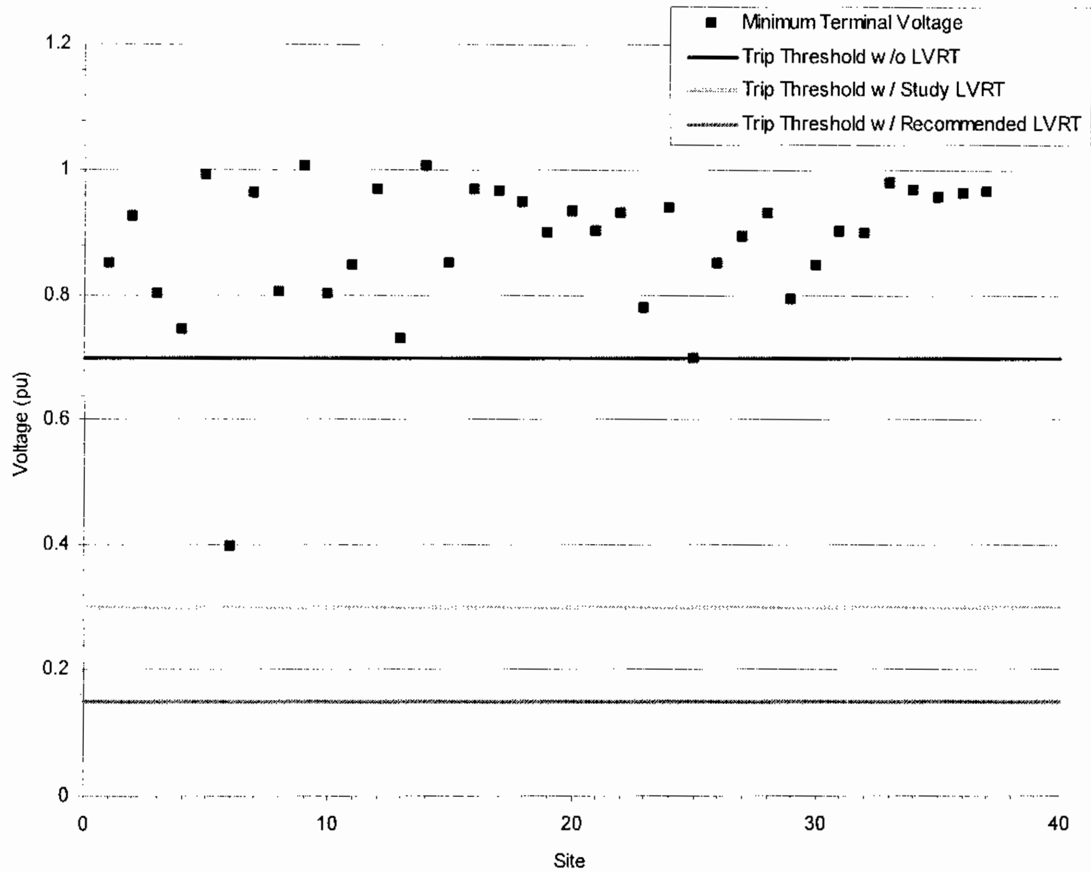

Figure 6.22. Minimum Terminal Voltages for All Wind Farms in LVRT Example.

6.2.2.1.3 Voltage Regulation

The ability of individual WTGs and entire wind farms to regulate voltage varies. Historically, WTGs with induction generators were not required to participate in system voltage regulation. Their reactive power demands, which increase with active power output, were typically compensated by switched shunt capacitors. This compensation was somewhat coarse, in that the capacitors are switched in discrete steps with some time delay. Therefore, many large wind farms, particularly those with interconnections to relatively weak transmission systems, are now designed to provide voltage regulation. These farms include supervisory controllers that instruct components of the wind farm (WTGs, shunt capacitors, etc.) to regulate voltage, usually at the POI (point of interconnection), to a specified level. Many new wind farms also accept a reference voltage that is supplied remotely by the system operator.

Of these various types of WTGs, only vector controlled WTGs have the inherent ability to control reactive power output from the generator, and therefore to regulate voltage. For the other WTGs, additional equipment is required to compensate for the generator's reactive power consumption and to meet the reactive power needs of the host grid. In applications on relatively weak systems, the addition of fast-acting solid-state reactive power equipment may be required to meet the voltage regulation requirements with these other types of WTGs. In general, however, fast and tight voltage regulation is possible with any properly designed wind farm.

Therefore, the impact of voltage regulation on system performance was evaluated in this study by comparison to reactive power regulation. Voltage regulation is achieved by a closed loop adjustment to the reactive power order. The reactive power control is achieved by a closed loop adjustment of reference voltage, and is effectively regulating to near unity power factor. This is only one example of a reactive power control.

The results of two Marcy fault simulations, with and without voltage regulation, are shown in Figure 6.23. The left column shows selected wind farm variables at a particular site with voltage regulation, and the right column shows the same variables at the same site with reactive power regulation. The top row of plots show wind farm terminal bus voltage (pu, solid line) and reference voltage (pu, dotted line). The second row of plots show wind farm reactive power output (MVAr, solid line) and reactive power reference (MVAr, dotted line). The results with voltage regulation show a fast recovery and that the minimum post-fault terminal bus voltage is greater than 1.00pu. With reactive power regulation, the recovery is slower and the minimum post-fault terminal bus voltage is about 0.92pu. The reactive power output, however, is regulated to its reference. Other reactive power control schemes are possible, and would have a similar impact on system performance.

Long term stability simulations, 600 seconds in duration, were also performed with and without voltage regulation. Instead of a fault disturbance, the simulation was driven by selected August load and wind profiles.

The impact of voltage regulation on Adirondack 230kV bus voltage performance is illustrated in Figure 6.24. The solid line (top) represents voltage regulation, the dotted line (bottom) represents reactive power regulation, and the dashed line (middle) represents system performance without wind. Note the drift in bus voltage with reactive power regulation as well as in the case without wind. The addition of wind farms with voltage regulation capability improved the transmission system voltage profile.

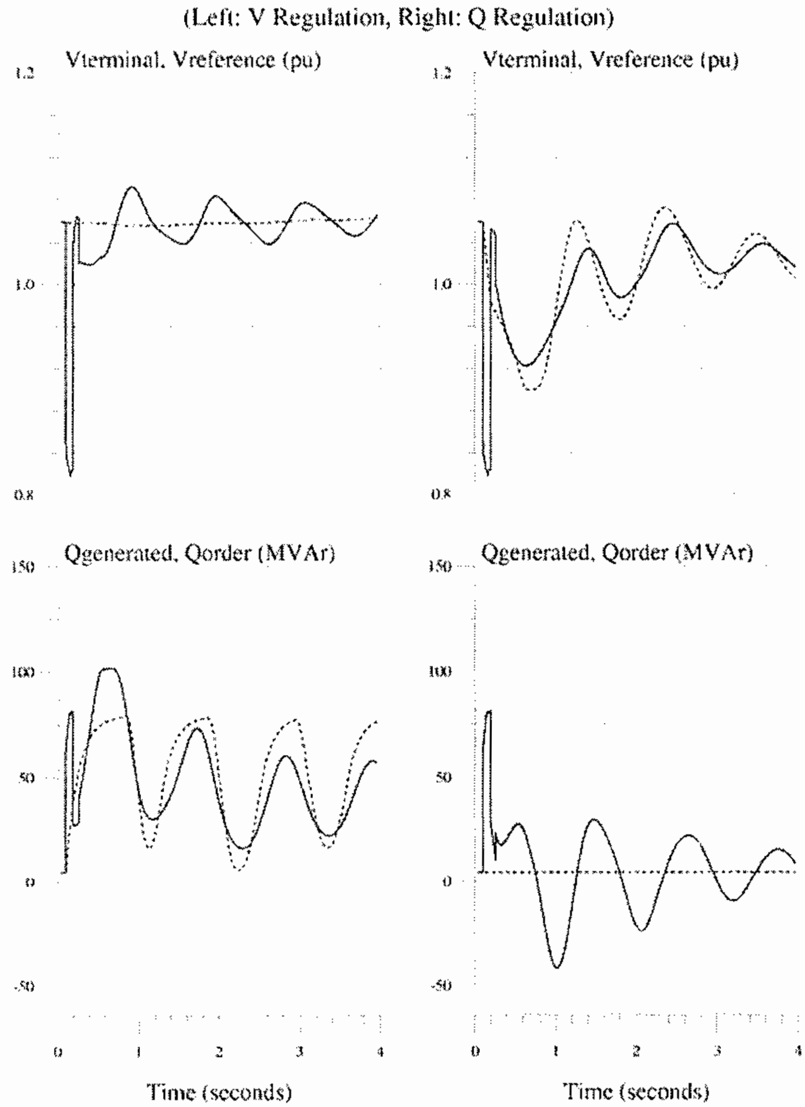

Figure 6.23. Local Performance with and without Voltage Regulation.

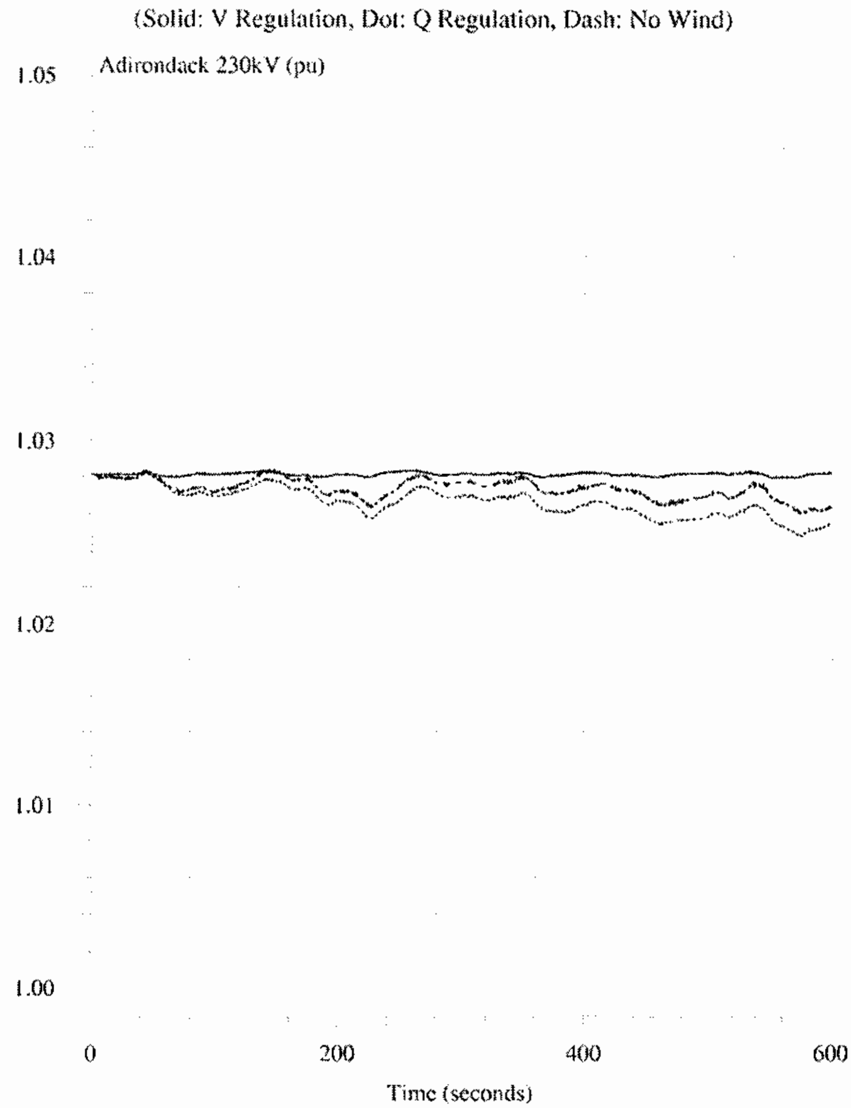

Figure 6.24. System Performance with and without Voltage Regulation.

6.2.2.1.4 Wind Turbine-Generation Technology

As noted in the "Technical Characteristics"[xiii] document, the type of WTG technology can have a significant impact on system performance. As noted in Section 6.2.1.1.1, *Power Flow and Dynamic Databases*, the bulk of this study was performed using vector controlled WTG models. To illustrate the different levels of performance inherent in the different types of WTG technology, additional fault simulations were performed. The response of vector controlled WTGs was compared to stall regulated WTGs to bracket performance. Scalar controlled WTG performance would fall in between that of the other two types of WTG. Therefore, it was not evaluated for this study. Details of the dynamic models are provided in Appendix D.

The impact of WTG technology on Marcy 345kV bus voltage performance is illustrated in Figure 6.25. The solid line represents vector controlled WTG performance and the dotted line represents conventional stall regulated WTG performance. The post-fault voltage was about 2% lower with the stall regulated WTGs.

The impact of WTG technology on an individual wind farm is illustrated in Figure 6.26. Selected variables for one wind farm site are shown. Again, the solid line represents vector controlled WTG performance and the dotted line represents stall regulated WTG performance. Real power output (MW), reactive power output (MVAr), and terminal bus voltage (pu) are shown. With the stall regulated WTG, reactive power consumption is significant, real power output is not maintained and the terminal voltage recovery is slow. By contrast, vector controlled WTGs maintain real power output and provide fast voltage recovery. The reactive power output, which moves in response to overall system oscillations, is also reduced. Note the significant difference in terminal voltage. It drops below 0.90pu with the stall regulated WTG, but remains above 1.00pu with the vector controlled WTG. Some improvement in stall regulated WTG performance could be achieved with the application of dynamic var compensation equipment.

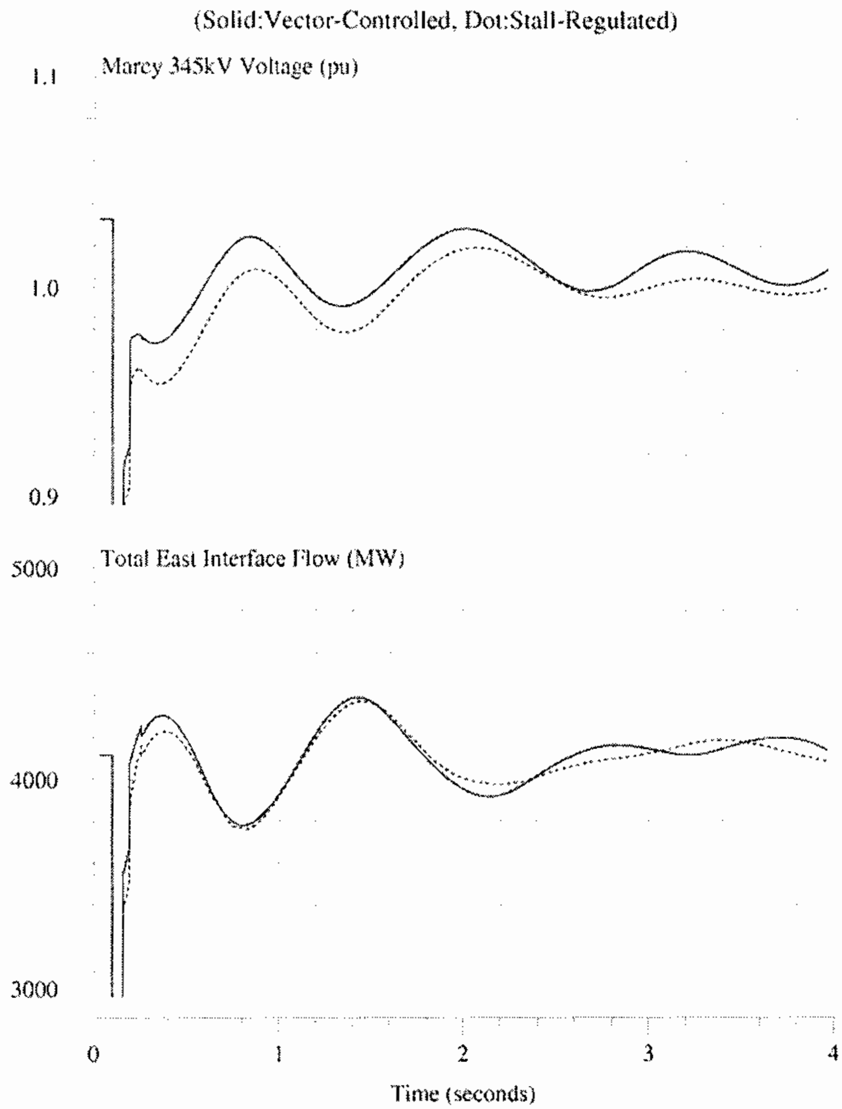

Figure 6.25. System Performance with Different Types of WTGs.

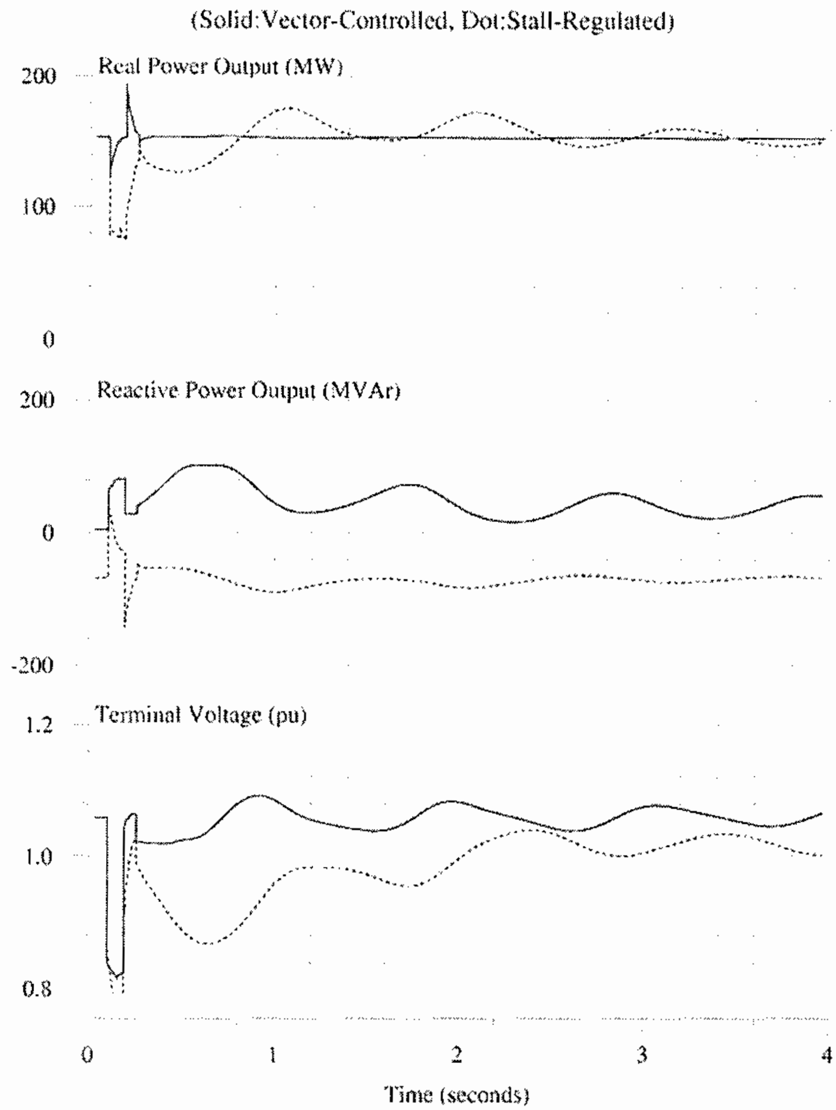

Figure 6.26. Local Performance with Different Types of WTGs.

6.2.2.1.5 Frequency Response

NPCC requires generating units to meet specific frequency performance criteria. NPCC Document A-5 *Bulk Power System Protection Criteria* states that "generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system", which implies that over- and/or under-frequency protection should not operate for fault disturbances that result in a stable system response. NPCC Document A-3 *Emergency Operation Criteria* identifies a specific under-frequency region in a frequency vs. time curve for which generating units are not allowed to trip. This document does not specify an over-frequency requirement.

A fault resulting in the loss of significant generation was used to test system response to frequency excursions, with and without wind generation. The test fault was applied at the Scriba 345kV bus and resulted in the trip of the 9 Mile Pt 2 unit for a loss of approximately 900MW of generation. The response of a selected wind farm (Site 6) is shown in Figure 6.27. The solid line represents system performance with wind generation, and the dotted line represents system performance without wind generation. Interconnection bus frequency (Hz) and interconnection bus voltage (pu) are shown. The frequency excursions are similar, with and without wind generation, but the voltage recovery is faster with the wind generation. The key point, however, is that no wind farms trip in response to these stable frequency swings.

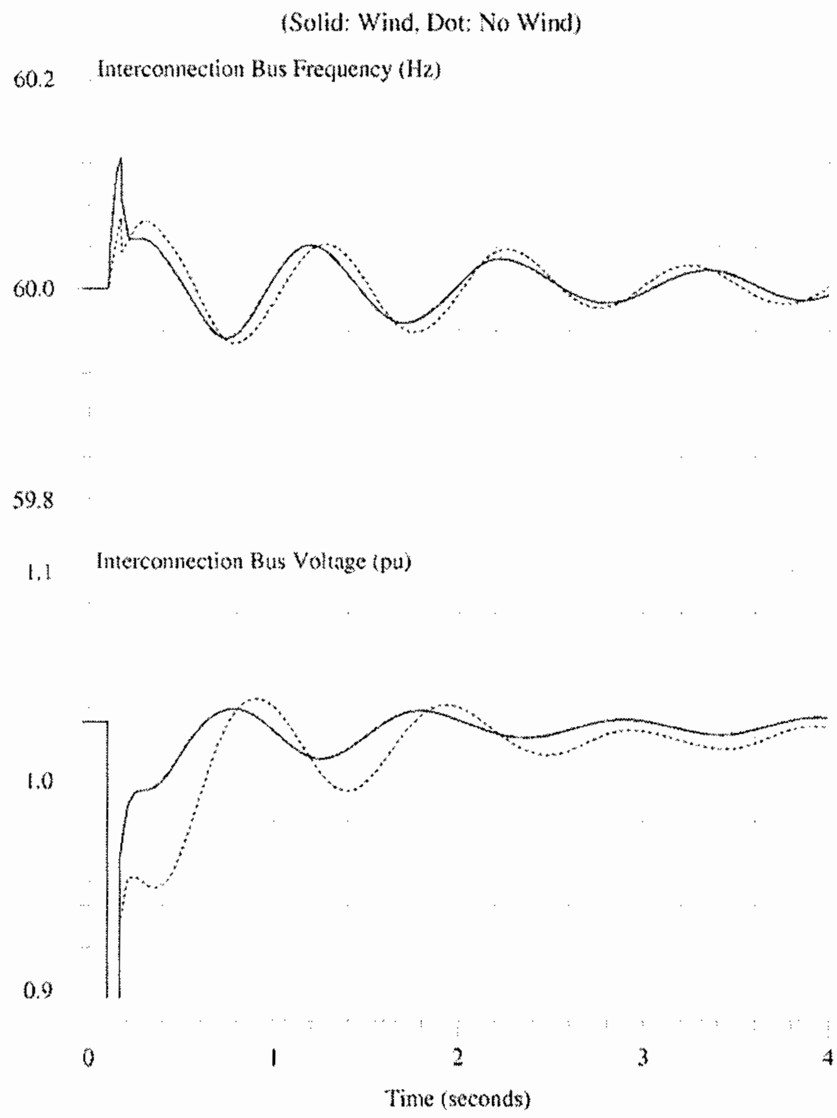

Figure 6.27. System Response to Frequency Swings with and without Wind Generation.

6.2.2.2 System Performance

The impact of significant amounts of wind generation on system-wide performance is discussed in this section. Specifically, long-term (10-minute) automatic generation control (AGC) performance was evaluated.

The objective of an AGC is to maintain 1) system frequency and 2) tie flows between control areas. For this analysis, NYISO's AGC was approximated with the model shown in Appendix E. Long-term stability simulations (600 seconds) were performed to evaluate the impact of wind generation on AGC performance. Specifically, the objective was to determine any increase in regulation requirements due to the addition of wind generation to the New York system. The benchmark case tested AGC response to an August morning load rise. The comparison case tested AGC response to the combination of an August morning load rise and an August morning wind generation decrease.

Figure 6.28 shows selected system and AGC variables. The solid line represents system response to both the August morning load and wind profiles and the dotted line represents system response to only the August morning load profile. The top plot shows New Scotland 345kV bus frequency (Hz). The second plot shows total New York State load (MW), which is the same in the two cases. The third plot shows the area control error (ACE), which is the difference between scheduled tie flow and actual tie flow plus a frequency bias component. The fourth plot shows the area tie flow (MW), which is the sum of the power flow on all ties between New York State and its neighbors. The bottom plot shows the total output of all New York generating units controlled by the AGC (MW).

The frequency trace shows that the AGC is meeting its objective to maintain frequency. The somewhat fuzzy nature of this trace is due to the numerical differentiation and plotting interval. There is little difference between the bus frequency with and without wind generation.

Note that the addition of wind generation has changed the area tie flows and therefore the ACE. In addition, the load following requirement has also increased. Following standard stability analysis practice, no economic redispatch or unit commitment changes were made during the course of the simulation. Therefore, all of the load following was performed by the units on AGC. As a result, the units under AGC control are generating more power with wind than without wind. At the end of the simulation, the difference in total output of the AGC units is approximately 150 MW. This overall rise in AGC output is conservative, as a realistic generation schedule based on an economic dispatch would offset the load following component. Therefore, as long as load following units meet their objectives, the AGC units will see similar duties, with or without wind generation.

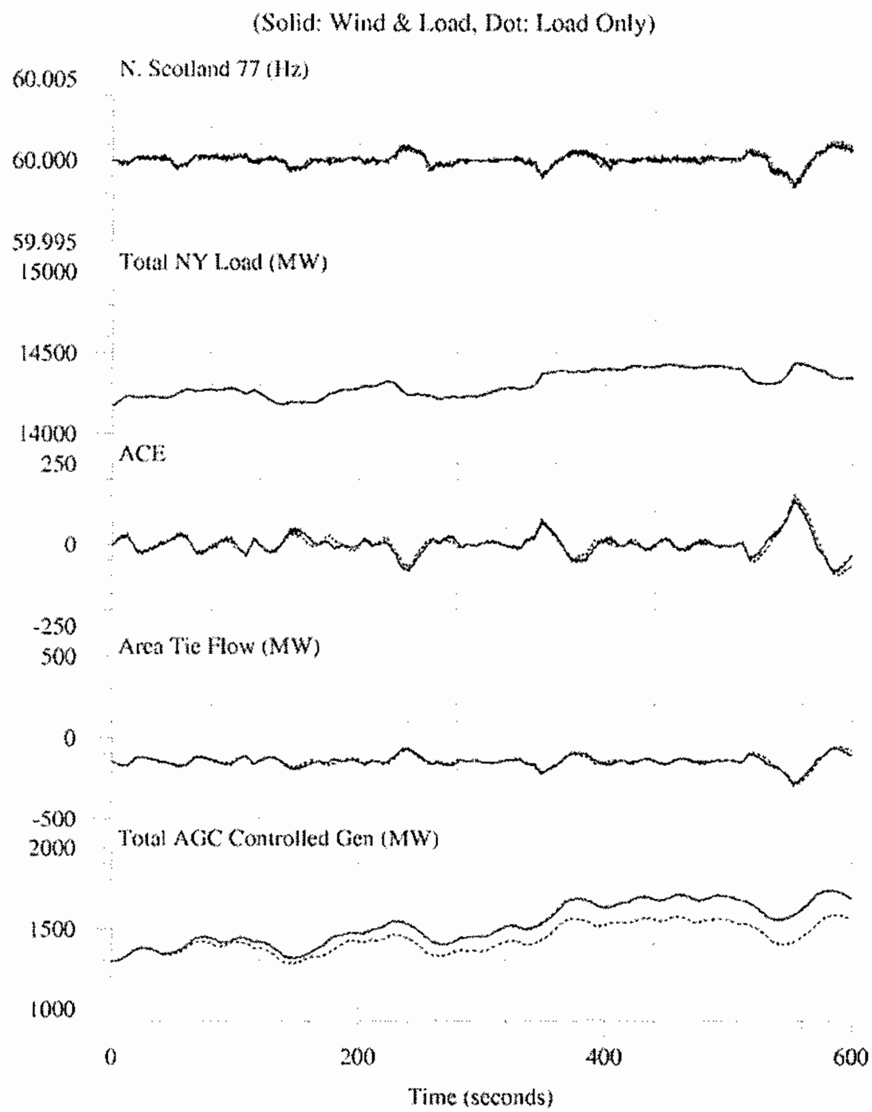

Figure 6.28. AGC & Frequency Response to August Load and Wind Profiles.

6.3 Conclusions

The QSS and stability time simulations discussed in this section were representative illustrations of system performance, intended to provide context for the statistical analysis presented in Section 5, *Wind and Load Variability*. The simulations illustrated the impact of significant amounts of wind generation on the New York State power system's load following capability, regulation requirements and overall transient stability. In addition, the performance of selected farm-level functions (e.g., LVRT, voltage regulation, WTG technology, active power control) was illustrated.

The study scenarios were selected to be severe, but likely, tests of the operational impacts of significant amounts of wind generation on New York State system performance. The QSS results, as well as the statistical analysis performed in Section 5, *Wind and Load Variability*, show that 3,300 MW of wind generation will impose additional load following duty on the economically dispatched units. No change in unit commitment is anticipated, but some of the load following may be performed by sub-economic units to respect the 1%/minute load following capability of individual units. The required load following duty appears to be within the capability of the existing system.

The results of the long-term stability analysis showed that the addition of wind would have little impact on the second-to-second response of the AGC. Therefore, as described in Section 5.4.1, *AGC Performance*, NYISO's existing level of regulation should be adequate with the addition of 3,300 MW of wind generation.

As described in Section 6.2.2.1.1, *Overall Stability Performance*, the transient stability behavior of wind generation, particularly vector controlled WTGs, is significantly different from that of conventional synchronous generation. The net result of this behavior difference is that wind farms generally exhibit better stability behavior than equivalent (same size and location) conventional synchronous generation.

Phase 1 of this project recommended that New York State require all new wind farms to have certain features. The impact of the two selected features, voltage regulation and low voltage ride through (LVRT), on system performance was demonstrated in this section. Voltage regulation improves system response to disturbances, ensuring a faster voltage recovery and reduced post-fault voltage dips. LVRT ensures that wind farms remain connected to the NYSBPS under low voltage conditions due to faults or other system disturbances. Therefore, the Phase 1 recommendations are substantiated by the simulation results described in Sections 6.2.2.1.3, *Voltage Regulation,* and 6.2.2.1.2, *Low Voltage Ride Through (LVRT).*

Good performance was demonstrated with LVRT parameters that are less aggressive than the emerging industry consensus. However, it is recommended that NYS adopt the emerging LVRT specification. That specification appears to be converging on the E-ON Netz based requirement of 15% retained voltage at the point of interconnection for 625 milliseconds, rising linearly to 90% retained voltage at 3 seconds as shown in the FERC NOPR on wind generation interconnection requirements[xiv].

Phase 1 also identified other farm-level functions that should be considered by New York State as potential future requirements. Of these, the ability to set power ramp rates for wind farms was demonstrated in Section 6.1.2.3, *Active Power Control.* The example ramp rate limit function resulted in a decrease in regulation requirements at the expense of energy production. To minimize the associated economic losses, such a function should only be used in specific applications to ensure system reliability. Again, the Phase I recommendations are substantiated by the simulation results shown in this section.

7 Effective Capacity

7.1 Introduction

This section examines the effective capacity of wind generation. Typical thermal generation can supply capacity on demand, 24 hours a day, all week long. A 100 MW unit can provide 100 MW of capacity whenever called upon. Even recognizing generator forced outages has a predictable outcome since the outages are assumed to be random throughout the year. Therefore, if a 100 MW unit has a 10% forced outage rate, then there is a 90% probability that the unit will be available whenever it is called upon and its UCAP, or Unforced CAPacity, would be 90 MW as opposed to its ICAP, or Installed CAPacity, of 100 MW.

While a wind turbine may be expected to have a 30% capacity factor for the year, it would NOT be proper to view that as a 70% forced outage rate since the outages are NOT random. There is a definite seasonal and diurnal pattern to the wind output, and how this wind output aligns with the system demand will have a significant effect on its capacity value.

Historical NYISO load data for 2001, 2002 and 2003 was used for the analysis in this section. Wind outputs were also developed for 3,300 MW of installed capacity spread out across 33 sites on the system. The wind output was developed from historical meteorological data for the same years. In order to capture the correlation of loads and wind output, if any, all analysis used this time-synchronized data from corresponding years.

7.2 Wind and Load Shapes

Figure 7.1 shows the average monthly capacity factor for the 3,300 MW of wind turbines examined for the years 2001 through 2003. While some months approached 50%, the summer months, during the NYISO peak loads, were as low as 20%. The annual average capacity factor was roughly 30%. Figure 7.2 shows the average daily profile for the same time frame. The hours from 10 a.m. to 6 p.m. have less than a 25% capacity factor while the evening and nighttime hours may be greater than 40%. Figure 7.3 shows the seasonal wind shapes for 2002. The average capacity factor in the summer is 23% for the entire day and only 13% for the 10 a.m. to 6 p.m. time frame.

Figure 7.4 shows the average NYISO loads and wind output for the months of July, August and September 2001. The load and wind shapes are almost completely out of phase with each other.

The primary benefit of wind generation occurs late in the day when the wind output is picking up before the loads have fully dropped off. Figure 7.5 shows a similar trend for the 2002 data.

The scatter plots in Figure 7.6 and Figure 7.7 show another way of comparing the annual correlation of the wind output and system load. If the wind were randomly distributed across the year then the plots would show a uniform density between the minimum and maximum loads. However, the upper right quarter of the plots, which represent the simultaneous occurrence of high load and high wind generation output, are particularly sparse.

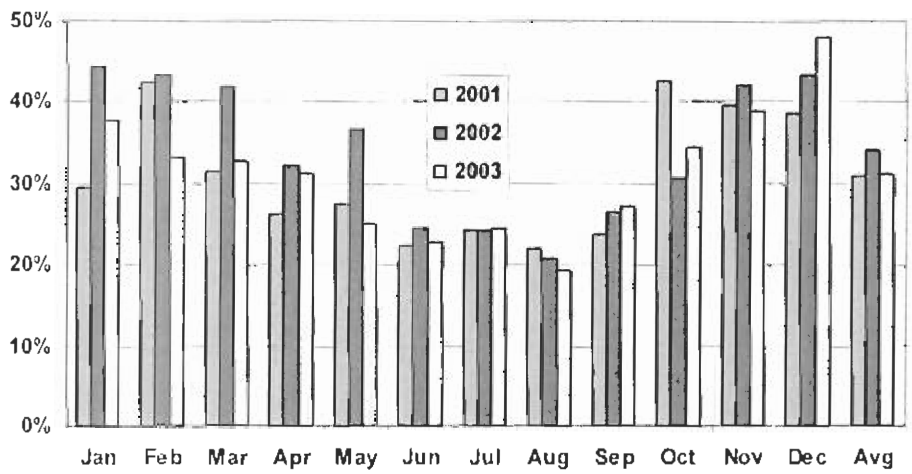

Figure 7.1 Monthly Wind Capacity Factors

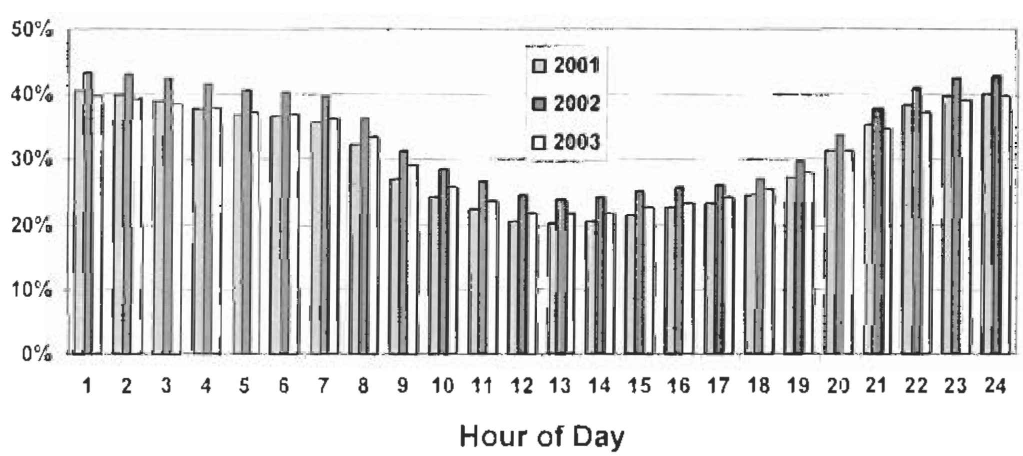

Figure 7.2 Hourly Wind Capacity Factors

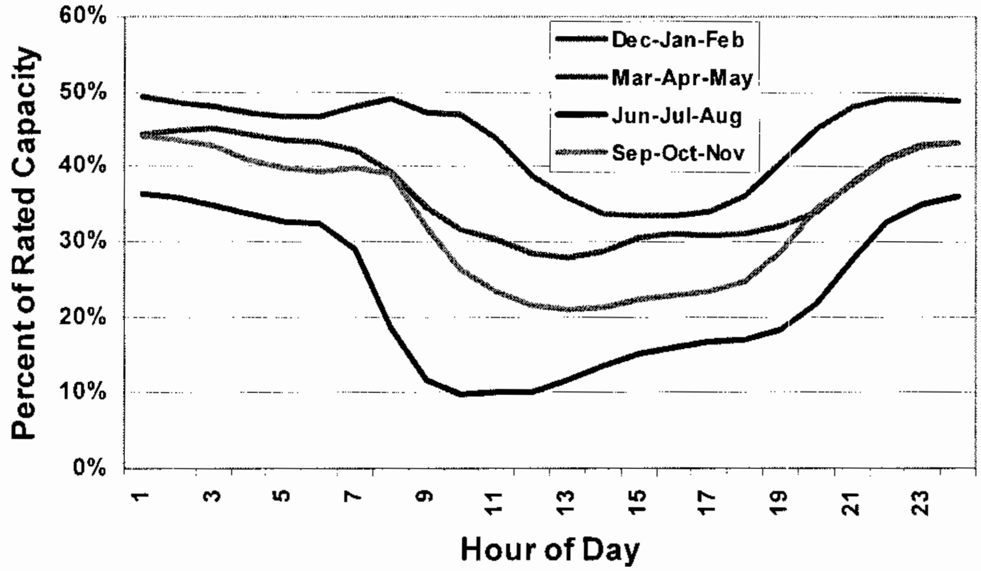

Figure 7.3 Average Seasonal Wind Shape, NYISO 2002

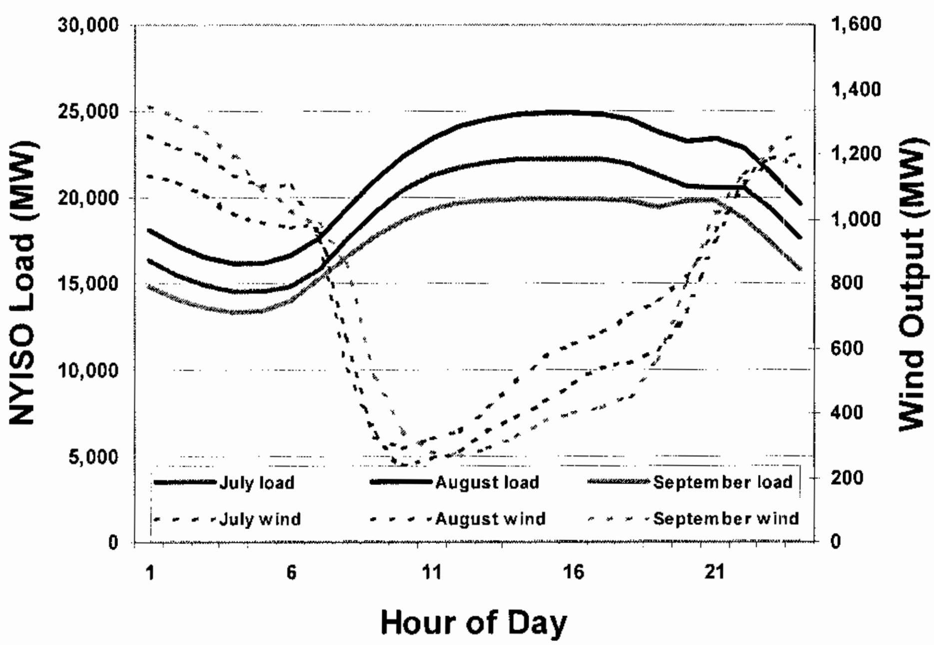

Figure 7.4 2001 Average Load versus Average Wind

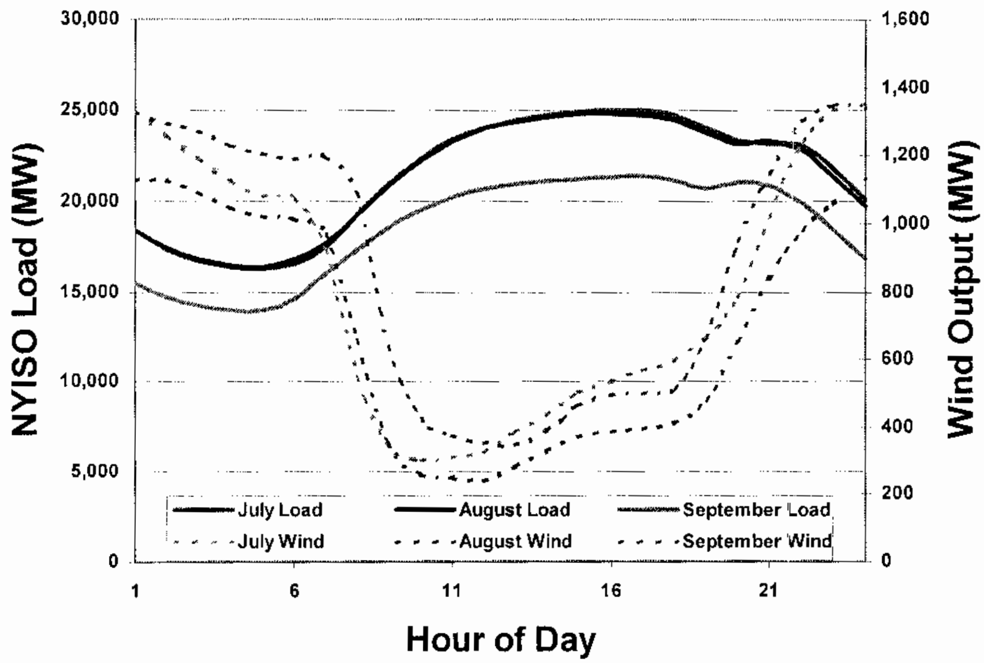

Figure 7.5 2002 Average Load and Average Wind

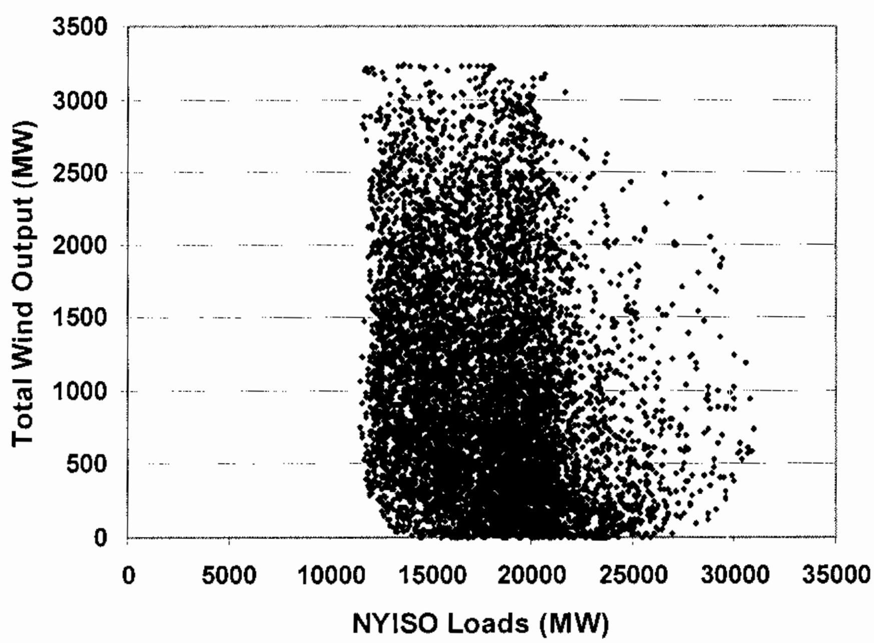

Figure 7.6 2001 Annual Load versus Wind Scatter Plot

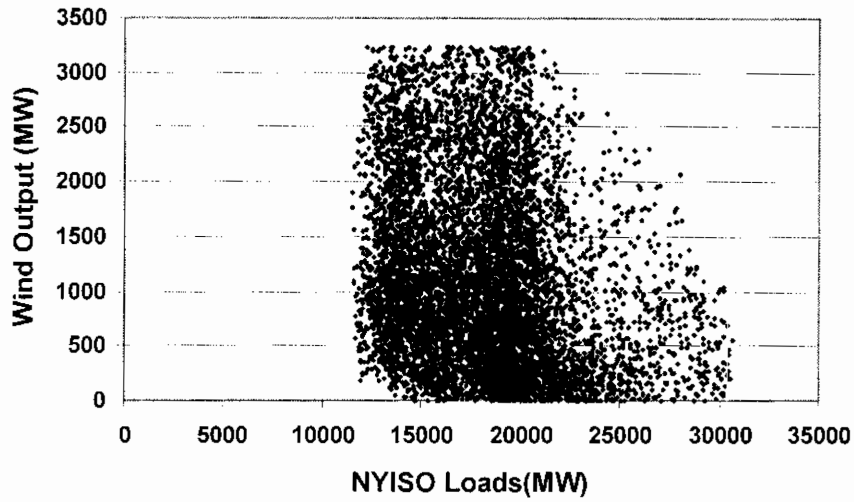

Figure 7.7 2002 Annual Load versus Wind Scatter Plot

The scatter plots in Figure 7.8 and Figure 7.9 show load versus wind for July and August of 2002. While these plots are somewhat more uniform in appearance it is important to note that there are few wind outputs above 2,500 MW even though the gross rating of all of the wind farms is 3,300 MW. Also, the plots are more dense below 1,000 MW of wind output than above.

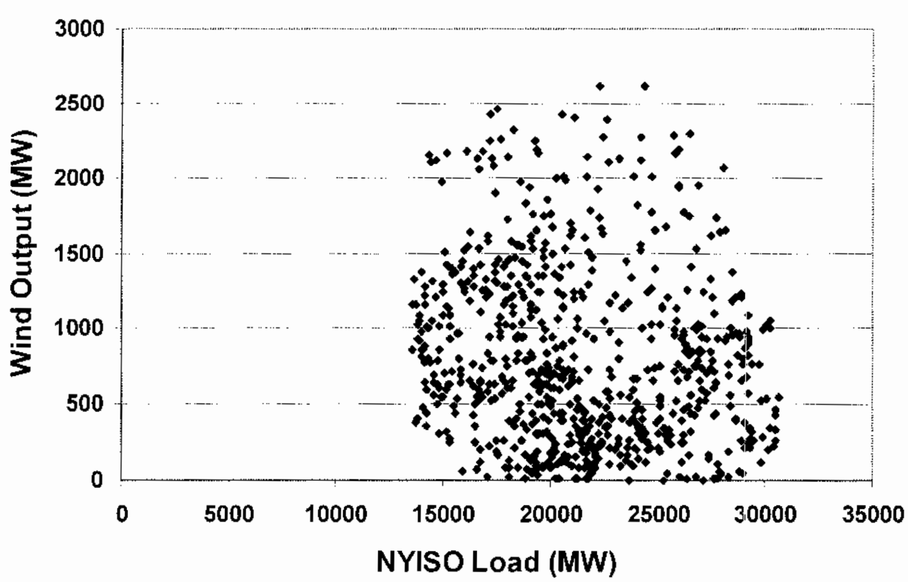

Figure 7.8 July, 2002 Load versus Wind Scatter Plot

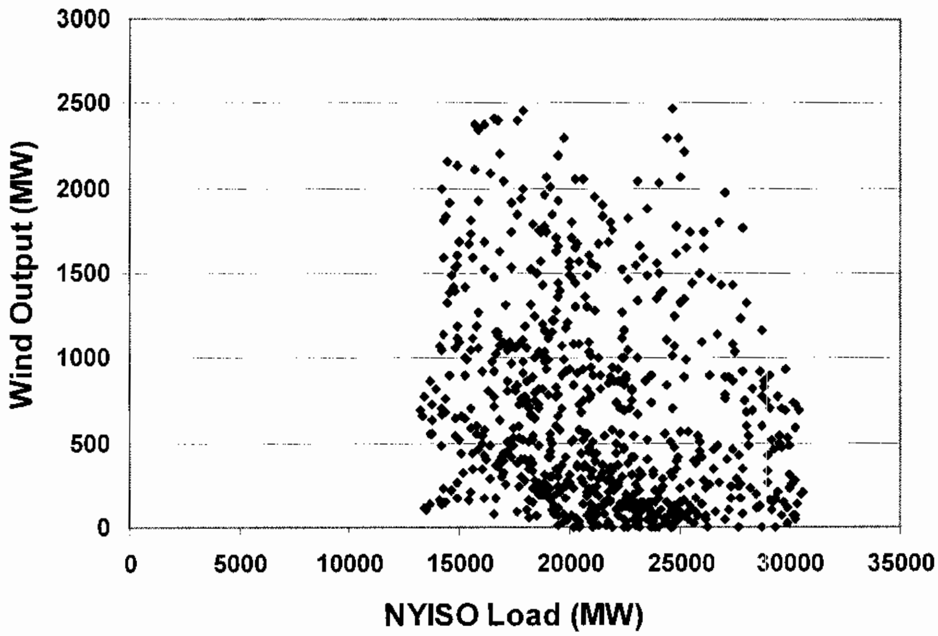

Figure 7.9 August, 2002 Load versus Wind Scatter Plot

Figure 7.10 shows the wind output and NYISO load for all of the days in July 2001. Although the wind occasionally exhibits higher values earlier in the day, most of the high wind output occurs during nighttime hours.

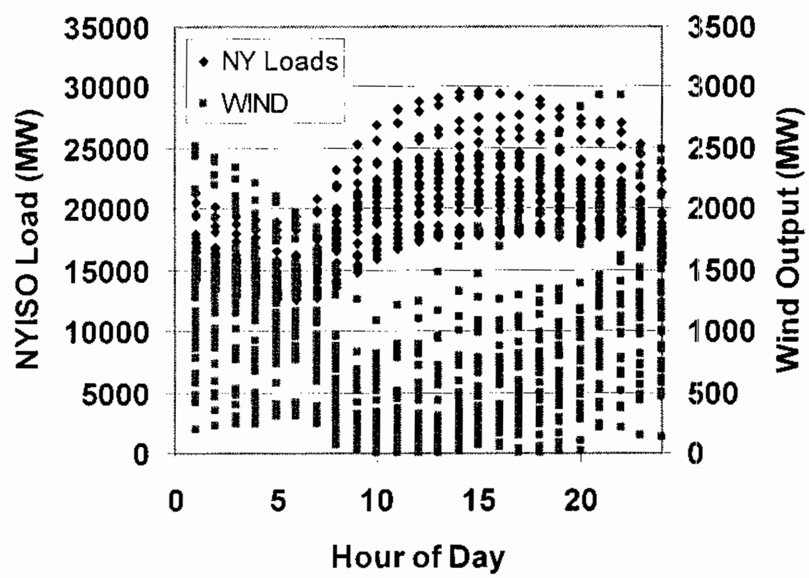

Figure 7.10 July 2001 Wind and Load versus Time-of-Day

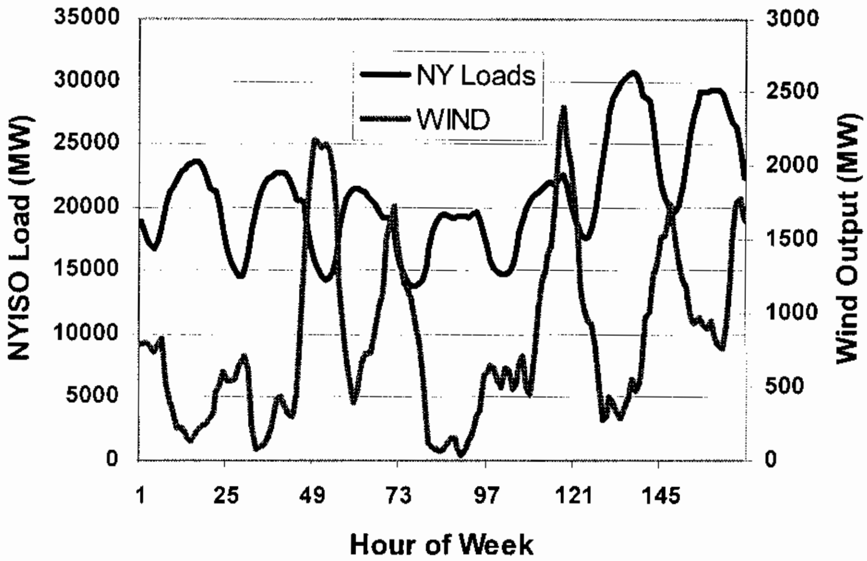

Figure 7.11 July 2002 Peak Week Wind and Load

Figure 7.11 shows the NYISO load and wind output for the peak week of July 2002. Although the wind generation reaches about 2,400 MW this week, its value at the time of the peak load is only about 500 MW.

7.3 LOLP analysis

The preceding analysis of daily and seasonal wind shapes illustrates how wind shapes correlate with loads. This section presents results of a standard Loss of Load Probability, LOLP, analysis on the system. The General Electric Multi-Area Reliability Simulation, MARS, program was used with the data from the NYISO's Installed Capacity Requirements study for May 2004 through April 2005. The peak loads were modified to represent the 2008 system. No additional generation was added since the existing system met the design targets of providing the New York Control Area, NYCA, with roughly 0.1 days/year Loss of Load Expectation (LOLE) on an interconnected basis. The 2001 and 2002 historical zonal load shapes were used along with the corresponding meteorological data to generate the output from the wind generation.

7.3.1 2001 and 2002 Analysis

Figure 7.12 shows the overall impact of the wind generation on the system LOLP. For each year of data, the system was first examined without the wind generation present. Although the analysis was performed using the 2008 peak load and energy projections the use of the historical

2001 or 2002 load curves caused a difference in the initial system risk levels. The 2002 load shape had more days with loads closer to the peak load than in 2001, causing the initial risk to be about 0.15 days per year in 2002 while it was only 0.05 days per year in 2001. This compares with the risk level of 0.11 days per year seen in the Phase 1 analysis of this study, which had used the 1995 historical load shapes. As a side note, recent studies by the NYISO have led to the adoption of the 2002 load shapes to replace the 1995 shapes in their studies since they are more representative of the current system load shapes and tend to produce slightly more conservative results.

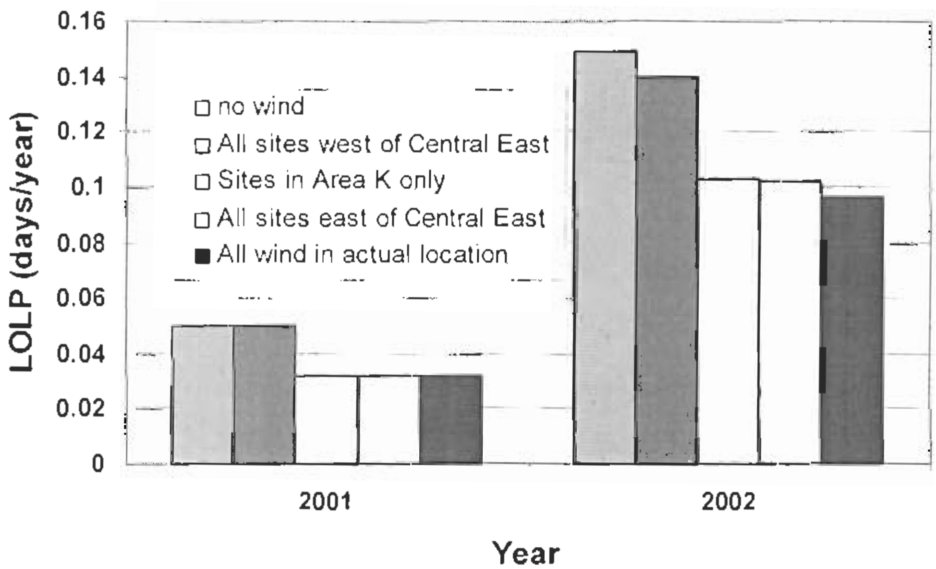

Figure 7.12 Annual Reliability Impact of Wind Sites

The columns on the far right of each group show the risk when all of the wind sites are added to the system. The intervening columns show the impact as various groups of the wind farms are added. In 2001 virtually all of the benefits, i.e., reduction in LOLP, come from the 600 MW site in Area K. The 2002 data shows some benefits from the other sites although the bulk of the impact still comes from the Area K site. (Note: In this report the terms "Area" and "Zone" are used interchangeably to describe the various geographic regions in the NYISO.)

7.3.2 UCAP calculations

While the fact that the risk is reduced from 0.05 to 0.032 days/year is interesting, the real question is how does that compare to the impact of adding a conventional generator to the system and how much of the value is due to the location of the wind farms versus the intermittent nature of their output.

Figure 7.13 represents the 2008 system risk for various scenarios based on the 2001 load and wind shapes. Of the three parallel lines, the top one represents the risk without the addition of any wind generation and the middle one represents the addition of the wind generation at their various sites across the state.

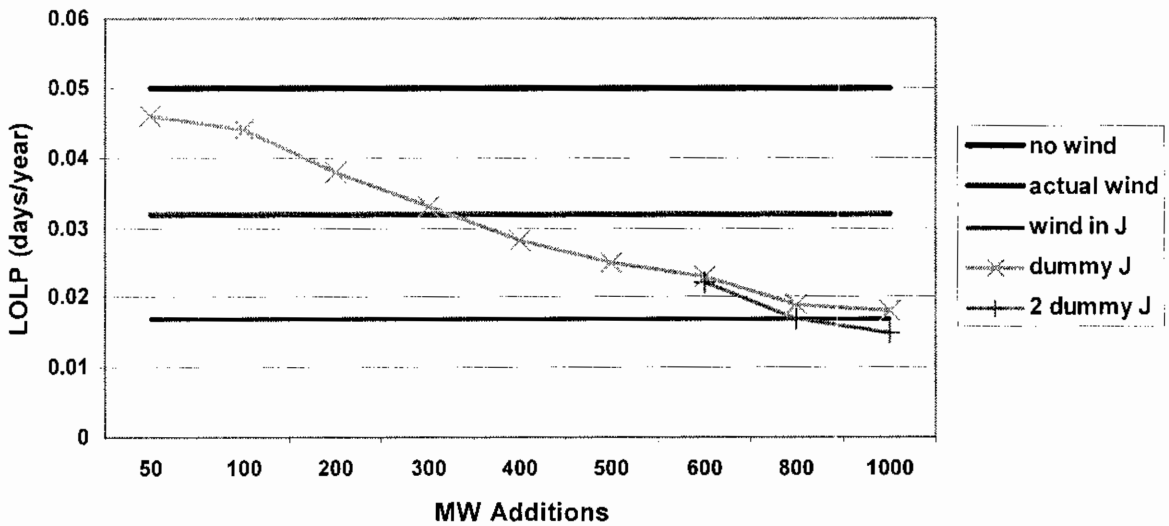

Figure 7.13 NYISO LOLP from 2001 Shapes

The bottom line represents the system risk impact if all of the wind generation shapes were assumed to occur in Area J, New York City. This indicates that 3,300 MW of wind generation with the 2001 hourly wind pattern would now further reduce the risk from 0.032 to 0.017 days/year if all of the wind generation were in New York City.

The curve slanting from upper left to lower right represents the addition of a conventional generator of various sizes with a 10% forced outage rate. Where the curves intersect represents the comparative value of the wind generation. In this case, the addition of the 3,300 MW of wind generation in their actual locations would have the same reliability benefit of adding a 300 MW generator in Area J, or about 270 MW (= 300 * .9) of UCAP. A saturation effect due to unit size occurs when the dummy unit exceeds 600 MW, so it was split into two dummy units. For the 2001 data, the 3,300 MW of wind generation, based on its output alone and not its location, would have the same impact on risk as 800 MW of conventional generation, or roughly 720 MW of UCAP.

Figure 7.14 shows the same analysis for the 2002 wind generation and load shapes. In this case the wind in its actual location is again comparable to about 300 MW of conventional generation in Area J, but its value independent of location is worth 500 MW, or about 450 MW of UCAP. Because the 2002 load data had risk contributions from a greater number of days, it provides a better measure of the value of the wind generation. The 2001 load data had fewer days contributing to the system risk and would therefore be much more affected by the performance, or lack thereof, of the wind on any given day. Also, as stated above, the NYISO has recently adopted the 2002 load shapes for future LOLP studies.

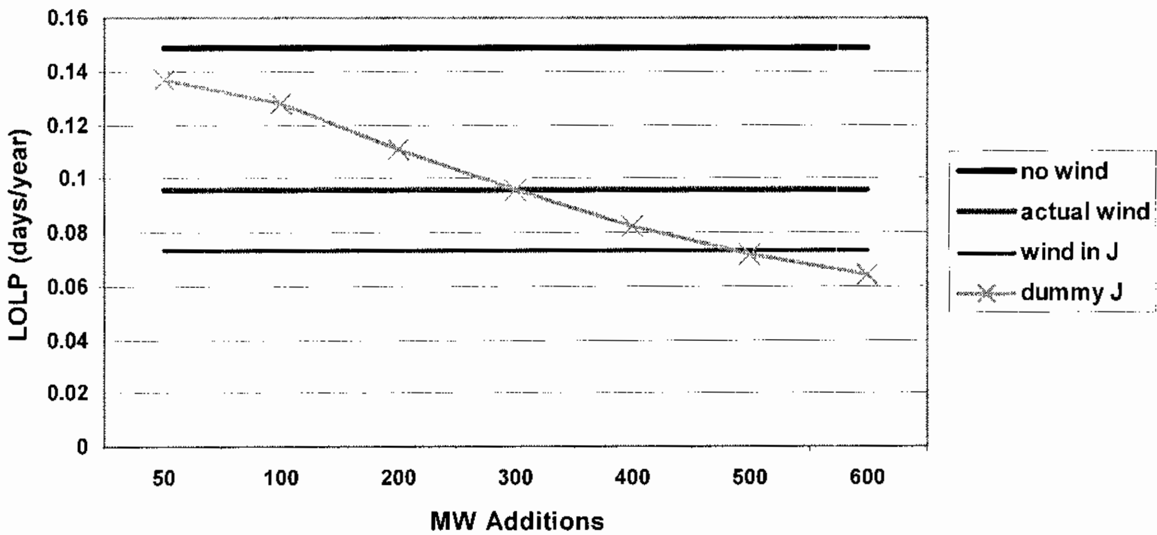

Figure 7.14 NYISO LOLP from 2002 Shapes

7.3.2.1 Comparison to Phase 1 Results

Figure 7.15 shows the results of the analysis in Phase 1 of this study. An additional curve, labeled "Dn EST," has been added to correct the original "Downstate" curve due to shifting the original wind generation to Eastern Standard Time. The Phase 1 analysis showed that when the wind generation was sited in Area J it had a risk impact equal to a thermal generator rated about 7% of the wind rating. The adjusted results increased that to about 9%. The Phase 2 results show that the capacity value of wind generation is 15% of its rating, i.e., 500 MW conventional generation is equivalent to 3,300 MW of wind. This variation is examined further in (the next) Section 7.3.3, *Approximate Techniques*.

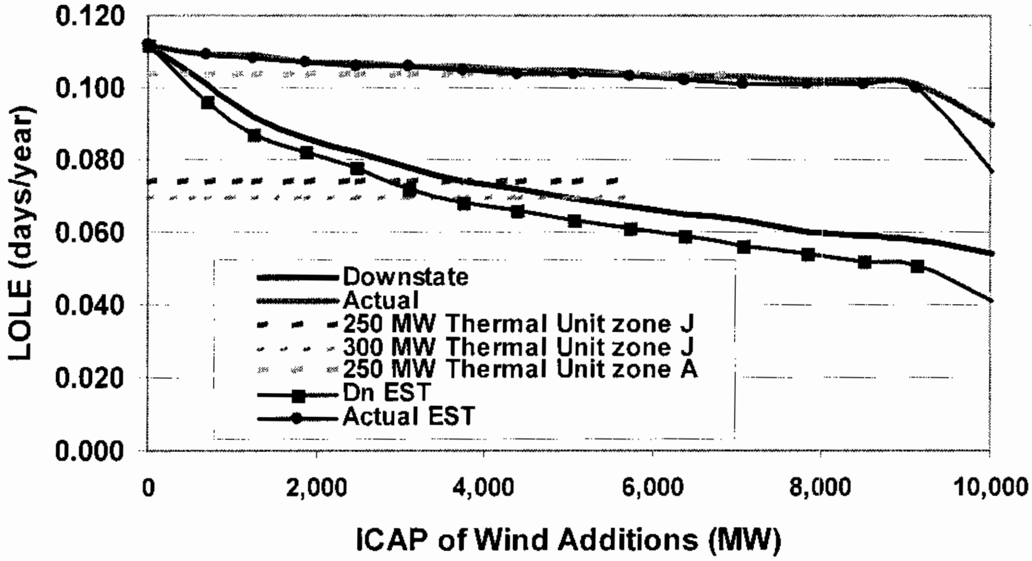

Figure 7.15 Phase 1 adjusted results

7.3.3 Approximate Techniques

While a detailed reliability analysis can show how much capacity value a wind generator is likely to produce, it would be helpful to have an easier, faster methodology to estimate the capacity value of wind generation. Figure 7.16 shows the NYISO daily peak load for 2003 with the summer months (June, July, August) highlighted in red. While the system risk is a function of many things, one of the key drivers is the load. The risk varies exponentially with peak load, so that essentially only loads above 90% of the peak provide significant contributions to the risk. Figure 7.16 illustrates why all of the risk generally occurs in the summer months.

The daily load shapes change slightly throughout the month. Figure 7.17 shows the hourly load shapes for June 2003. A few things stand out from these curves. First is that there are a few days above the rest of the pack in terms of their magnitude of loads. The second is that the peak load does not occur at the same hour every day. The NYISO reliability calculations only look at the peak load each day, not all of the hourly load values, so it is important to know when the peak occurs when evaluating the impact of wind generation. Figure 7.18 shows the hour of the day that the peak load occurred for the summer months in 2001 through 2003. Although other hours are present the bulk of the peak loads occur in the four hours of 14 through 17 inclusively. (Note, the period from midnight to 1:00 a.m. is hour 1.)

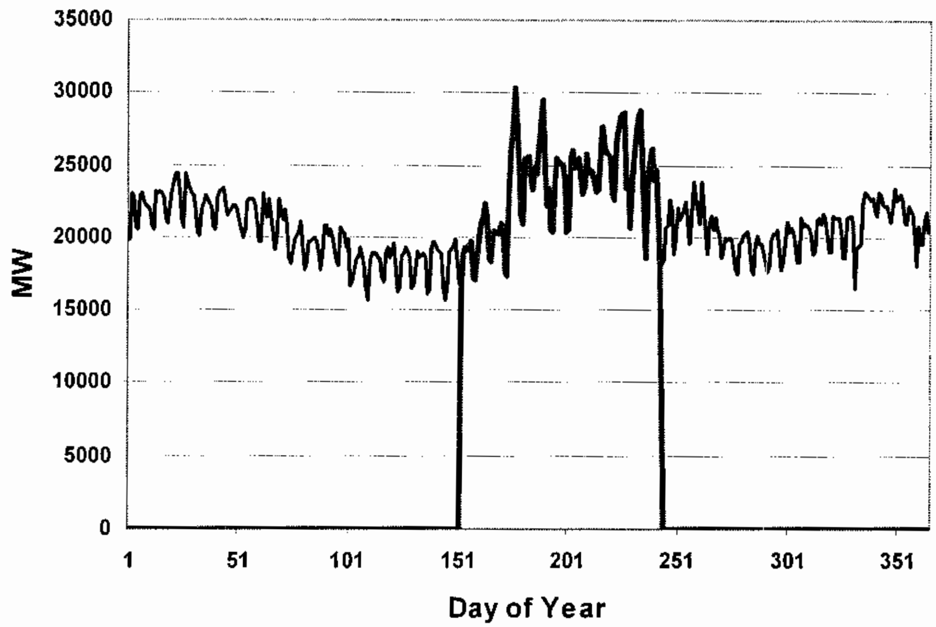

Figure 7.16 NYISO 2003 Daily Peak Load Profile

Figure 7.19 uses this four-hour definition to calculate a wind capacity factor for both all year and for the summer season. This is compared to the capacity factor for the entire year or for just those hours when the load is within either 5% or 10% of the peak load. Also shown, for the 2001 and 2002 shapes, is the effective capacity determined from the reliability analysis if either all of the wind is treated as being in area J or if the wind is represented in its actual location. While the value during only those hours that are within 5% to 10% of the peak are a good measure of the unit's effectiveness, it is difficult to estimate those hours in advance since both the wind and the loads are varying. The peak period in the summer is only a function of the wind and can be evaluated for various historical years for a site. This appears to give a very close approximation to the effectiveness based on just its intermittent nature ("wind in J"), particularly for the 2002 shapes.

This approximate technique can be used to investigate the difference between the Phase 1 results (~9%) and the Phase 2 analysis (~15%). Figure 7.20 shows the annual and peak capacity factors for all of the individual sites. Most of the sites range around 30% for the annual capacity factor and about 10% for the peak load period. The last site, in Area K, is an exception.

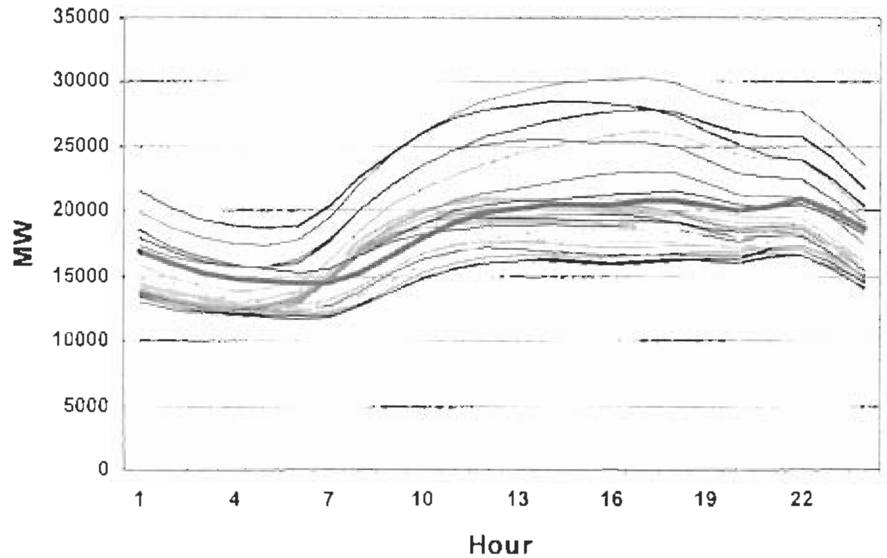

Figure 7.17 NYISO June 2003 Loads

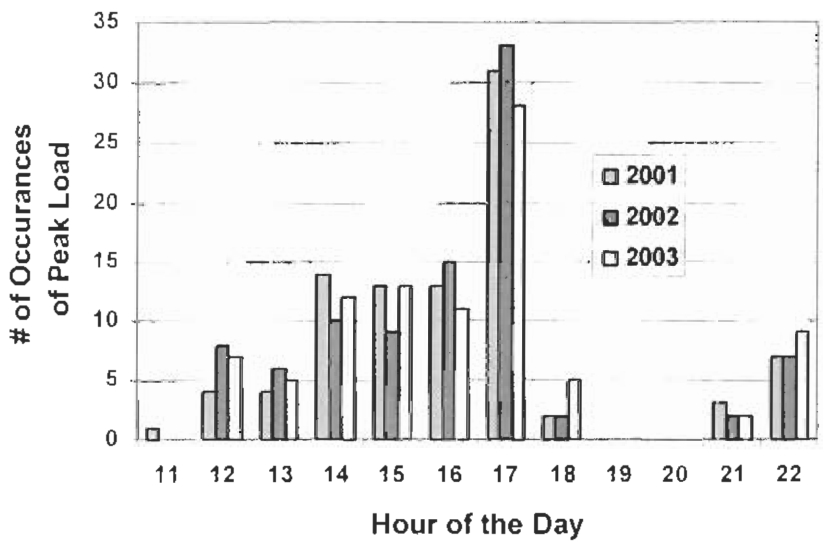

Figure 7.18 Peak Hour of the Day - Summer

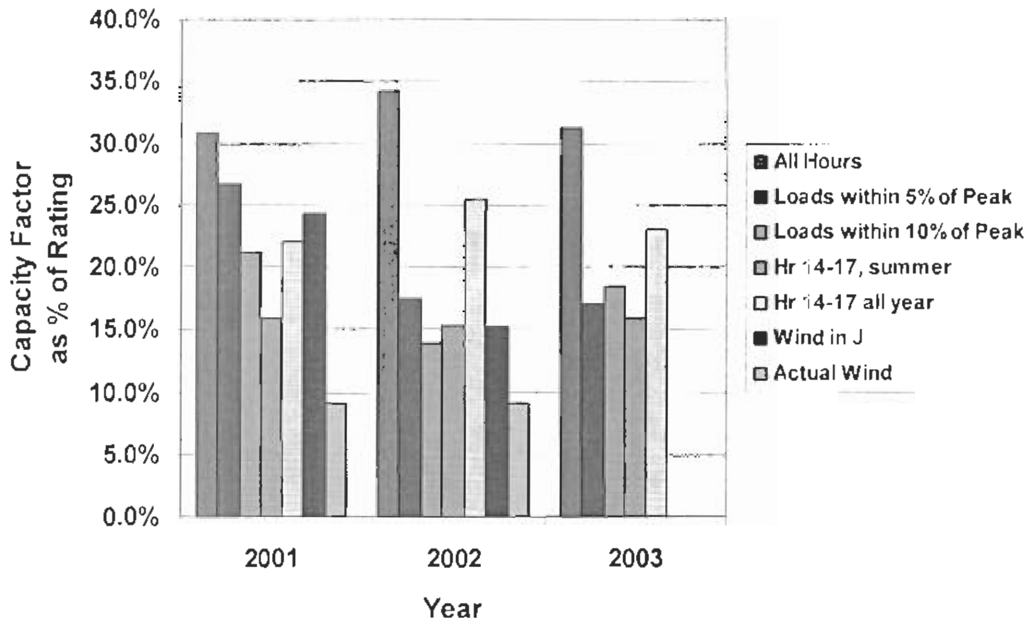

Figure 7.19 Wind Capacity Factors in Peak Load Hours

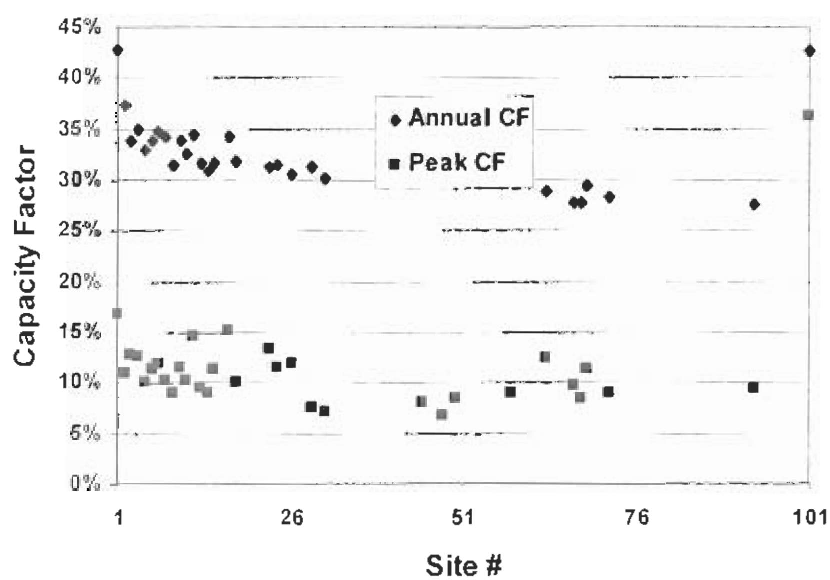

Figure 7.20 Annual and Peak Capacity Factors by Site for Year 2002 Shapes.

Figure 7.21 shows the key difference between the wind site in Zone K, which is an offshore location, and the rest of the wind sites in New York that are all inland. The offshore site has a much different daily pattern that peaks several hours earlier in the day and is much more in line with the load patterns.

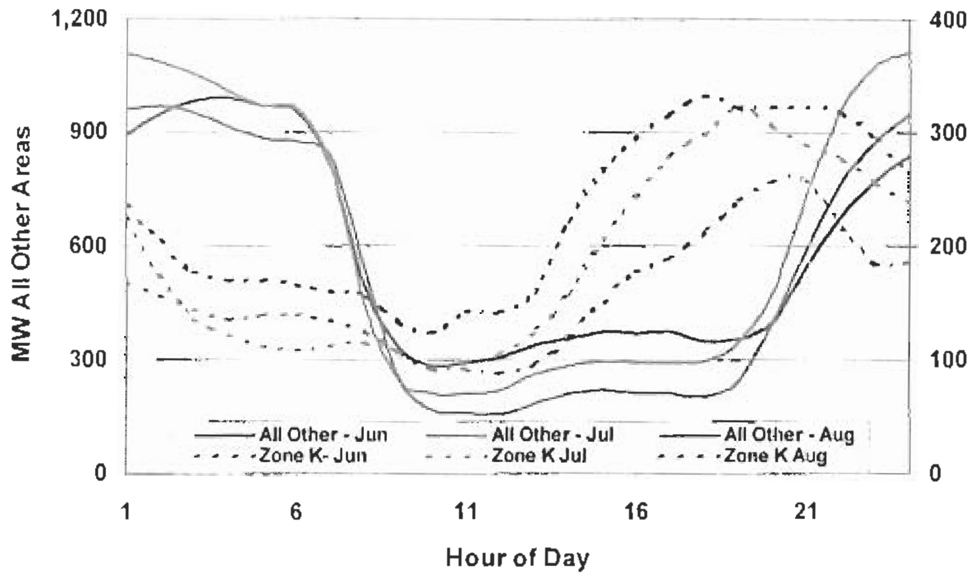

Figure 7.21 Average Hourly Wind Shapes for 2002 .

Figure 7.22 shows the annual and peak period capacity factors for the wind by zone and the NYISO average. Outside of Zone K the peak capacity factors ranged from 7% to 12%, which is much more in line with the results predicted in Phase 1. The Zone K values are above 35% in all years, and this is what brings the NYISO average values up to the 15% level. Figure 7.23 groups all of the inland sites together and shows that they average about a 10% capacity factor during the summer peak load period.

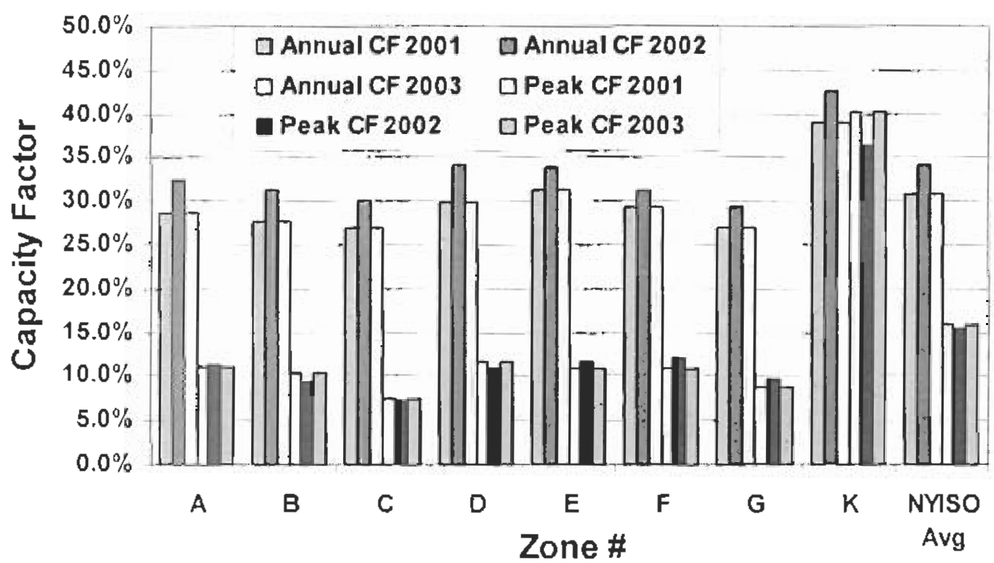

Figure 7.22 NYISO Wind Capacity Factors by Zone

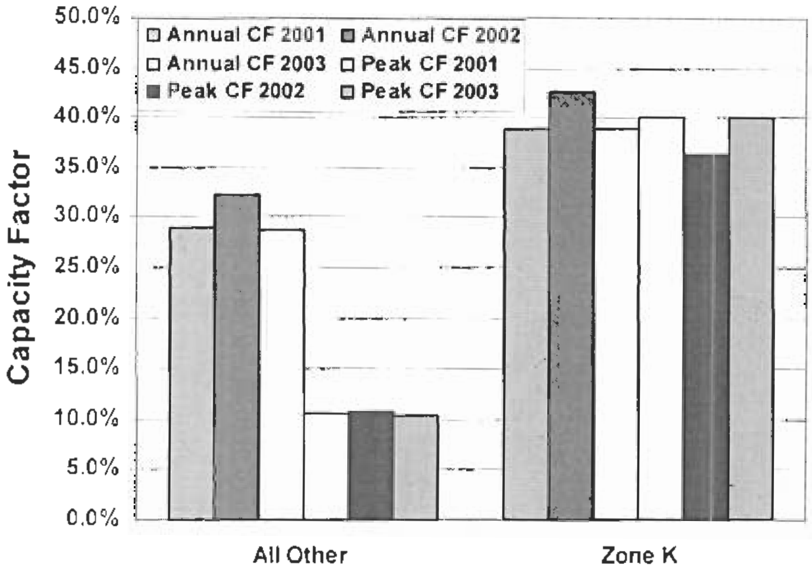

Figure 7.23 NYISO Wind Capacity Factors

7.4 Summary

Capacity factors of inland wind sites in New York are on the order of 30% of their rated capacity. Their effective capacities, however, are about 10%, due to both the seasonal and daily patterns of the wind generation being largely "out of phase" with the NYISO load patterns. The offshore site in Long Island exhibits both annual and peak period effective capacities on the order of 40%. The higher effective capacity is due to the daily wind patterns peaking several hours earlier in the day than the rest of the wind sites and therefore being much more in line with the load demand. As has been noted earlier, these capacity factors are based on the 2001 through 2003 meteorological data combined with the operating characteristics of the 1.5 MW GE wind turbine design. It is expected that future designs will show greater efficiencies with corresponding increases in effective capacities.

An approximate methodology was shown which bases the wind's effective capacity on the capacity factor during a four-hour peak load period, 1 p.m. to 5 p.m., in the summer months. This produces results in close agreement with the full analytical methodology based on LOLP. This methodology could be used with a "predicted" history based on historical meteorological data until such time that several years of actual operating history can be developed for a particular site.

8 Suggested Changes to Planning and Operating Practices

Previous sections of this report address the impact of wind generation on a diverse range of system operation and performance issues. Analytical results are described in detail, and the implications of those results are discussed.

One of this study's key objectives is to identify required changes to existing planning and operation practices due to the addition of wind generation in NY State. This section of the report draws from the analysis presented in other sections, and summarizes the impacts on existing planning and operating practices.

8.1 NYISO Planning Practices and Criteria

According to the NYISO's *System Reliability Impact Study Criteria and Procedures* document, the objectives of the SRIS are to:

1. Confirm that the proposed new or modified facilities associated with the project comply with applicable reliability standards.
2. Assess the impact of the proposed project on the reliability of the pre-existing power system.
3. Evaluate alternatives to eliminate adverse reliability impacts, if any, resulting from the proposed interconnection.
4. Assess the impact of the proposed project on transmission transfer limits, considering thermal, voltage and stability limitations, and estimate the increase or decrease in the Transfer Capability of affected transmission interfaces.

No changes to the SRIS criteria and procedures are recommended to accommodate wind generation projects. The key requirement in the SRIS rules is that any new project must comply with applicable reliability standards, and that should not change.

New York State Reliability Council (NYSRC) reliability rules are outlined in the document *NYSRC Reliability Rules for Planning and Operating the New York State Power System*. The reliability of the State power system is defined in terms of both resource adequacy and system security, then divided into eleven rule groups. Only those rules associated with transmission planning are discussed in this section.

The Transmission Capability – Planning rule group establishes guidelines for the planning of sufficient transmission resources to ensure the system ability to withstand design criteria contingencies without significant disruption to system operation. Both design criteria and extreme contingencies are evaluated in thermal, voltage and stability analyses. Recommended modifications or additional interpretations of the reliability rules applied to steady-state and stability analyses are discussed in the following subsections.

8.1.1 Impact of Wind Generation on Steady-State Analysis

Only selected issues relevant to the application of the NYSRC rules to steady-state analysis with wind generation are discussed in this section.

In accordance with the existing NYSRC rules, a steady-state analysis must evaluate design criteria contingencies (e.g., single element outages) as well as extreme contingencies (e.g., loss of all lines emanating from a substation). Single element (N-1) outages currently include the loss of a single generator, and it is recommended that an individual wind farm be considered a single generator for the purposes of this type of analysis. It is recommended that two types of wind farm design criteria outages be evaluated. The first outage is a conventional trip of the entire wind farm. The second outage actually represents the loss of wind, not the loss of the wind farm. This should be implemented as a reduction in wind farm power output from its initial value to zero, but with the wind farm still connected and therefore, still regulating voltage. The objective of this second type of test is to determine the change in voltage on buses in the local area and comparing the results to relevant criteria.

No changes to extreme contingencies, or multiple element outages, are recommended. The loss of wind across the entire state, for example, is not a credible outage. Loss of wind in local areas can be addressed under the existing rules. For example, the loss of all lines emanating from a substation is already included in the rules. Therefore, if two or more wind farms share a transmission substation interconnection, an assessment of the impact of the loss of these wind farms is a defined extreme contingency.

8.1.2 Impact of Wind Generation on Stability Analysis

Only selected issues relevant to the application of the NYSRC rules to stability analysis with wind generation are discussed in this section.

In accordance with the existing NYSRC rules, a stability analysis must also evaluate design criteria (e.g., a permanent three-phase fault on a generator with normal fault clearing) as well as extreme faults (e.g., permanent three-phase fault on a generator with delayed fault clearing). No changes in the interpretation of design criteria or extreme fault scenarios are recommended.

8.2 NERC, NPCC, and NYSRC Reliability Criteria

NERC, NPCC, and NYSRC policies and criteria were reviewed in Phase 1 of this project and documented in Chapter 6 of the Phase 1 report. The results of Phase 2 technical analysis reinforce the conclusions stated there.

The reliability standards themselves do not need to change to accommodate wind generation. The system should still be designed to meet a reliability criteria of 1 day in 10 years Loss of Load Probability, LOLP, and should still withstand the single largest contingency without causing cascading outages. However, the LOLP calculation methods should be modified to reflect the intermittent nature of the wind, as described briefly in (the next) Section 8.3, *NYISO Transmission Reliability and Capacity Requirements*, and more fully in Section 7, *Effective Capacity*.

One concern that was raised was "Would the introduction of 3,300 MW of wind generation create a new *most severe* single contingency?" Analysis of historical statewide wind data indicates that loss of wind generation due to abrupt loss of wind in not a credible contingency. Short-term changes in wind are stochastic (as are short-term changes in load).

A review of the wind plant data revealed no sudden change in wind output in three years that would be sufficiently rapid to qualify as a loss-of-generation contingency for the purpose of stability analysis. While the wind can vary rapidly at a given location, turbines are spread out in a project, and the projects are spread throughout the state, making such an abrupt drop in the total output an extremely unlikely event. It was concluded that each wind project can be treated as separate generating unit for contingency analysis.

Figure 8.1 below shows a histogram of the hourly deltas in wind generation from the assumed 3,300 MW of wind farms in New York. In general, the changes are well within ±600 MW and the extreme values are less that the ±1200 MW criteria. And these represent the changes from one hour to the next. Instantaneous changes, or changes within a few minutes, would be significantly smaller. There are hours with low wind output, as shown in Figure 8.2, but they are generally preceded by other hours that are also relatively low.

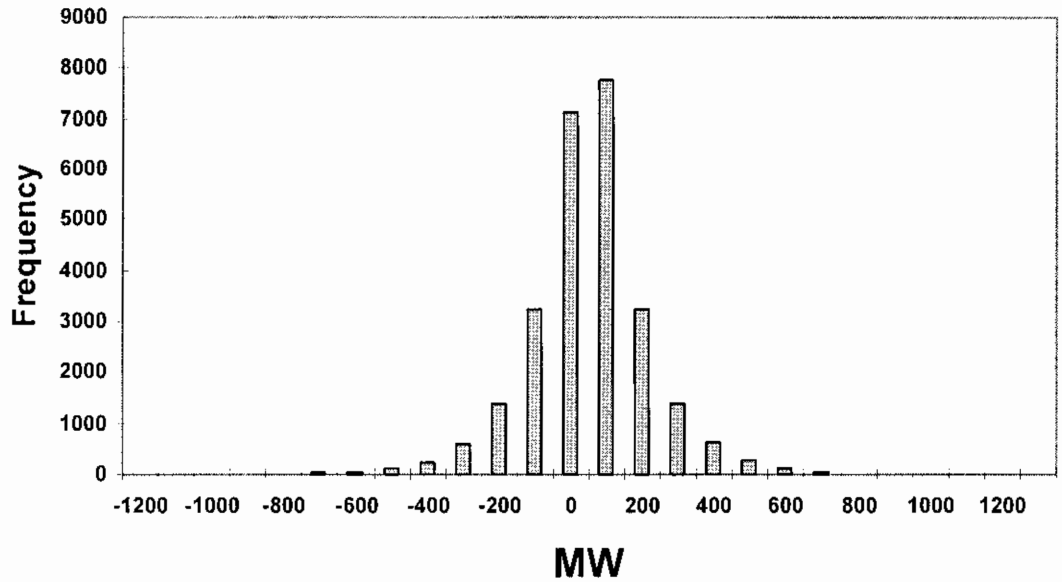

Figure 8.1. Hourly Wind Deltas, 2001 through 2003

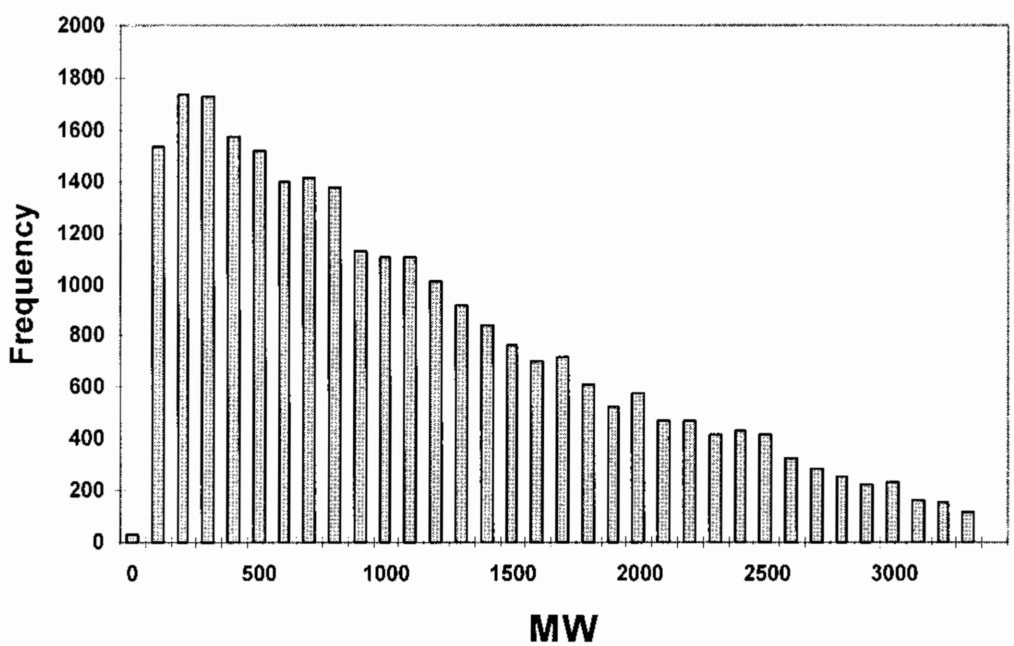

Figure 8.2. Hourly Wind Outputs, 2001 through 2003

8.3 NYISO Transmission Reliability and Capacity Requirements

The existing reliability assessment in New York is based on the Installed Capacity, ICAP, analysis performed each year which uses a Monte Carlo based program (MARS) to determine the amount of installed capacity required to meet a "one day in ten years" Loss of Load Probability, LOLP, based on the daily peak loads and recognizing transmission constraints and support from neighboring systems. This ICAP requirement, currently set at 18% reserves for the 2005 summer peak, is then converted to a UCAP, or Unforced Capacity, requirement based on the forced outages of the generators. The UCAP of a 100 MW generator with a 10% forced outage rate is 90 MW [= 100 * (1.0 –0.1)]. The current UCAP requirement is roughly 12% reserves. The UCAP is what is used in the bidding in the capacity market.

Because wind generation is an intermittent source that cannot be controlled, it needs to be evaluated in a manner different from conventional generation. But while its output can't be controlled (except downward) it can be predicted. Based on the analysis performed in this study, a 100 MW wind farm in upstate New York with a 30% annual capacity factor will have a UCAP of roughly 10 MW. A 100 MW offshore wind farm in Long Island may have a 40% capacity factor and a UCAP of 40 MW. The differences in their effectiveness are due the differences in their expected daily and seasonal patterns. This study recommends that the UCAP of wind generation be determined from the unit's expected capacity factor during the summer peak load period. This analysis determined that the four-hour period from hour 14 through 17 inclusive (2:00 to 6:00 pm) for the months of June, July and August, produced effective capacities in line with their overall reliability impact in the full LOLP calculations.

At present there is a locational requirement for New York City and Long Island which requires that a specified percentage of their UCAP requirements must be met locally. Other than that, there are no locational factors in the calculation of UCAP. A hypothetical 100 MW conventional generator with a 10% forced outage rate is worth 90 MW of UCAP whether it is in Buffalo or New York City. Therefore, there should be no locational consideration in the calculation of a UCAP for wind generation.

If a system ICAP needs to be determined, then the ICAP of the wind generation should be set equal to its UCAP in order to avoid any radical changes in the system ICAP values. If this is not done, then replacing 300 MW of conventional generation with 3,000 MW of wind generation (with a UCAP of 300 MW) would make the ICAP appear to rise from 18% to over 26%, resulting in a misleading measure of the system's installed capacity reserves.

8.4 Ancillary Services

Ancillary services in New York State include capacity (UCAP), regulation, and spinning reserves. The addition of wind generation to the NYISO should have minimal impact on the ancillary services market.

Capacity: The methodology for calculating the UCAP of wind must be different from the methodology for conventional generation, due to the variable nature of the power source (see Chapter 7). However, wind generation participation in the UCAP market should be exactly the same as for other units.

Regulation: A 36 MW (3σ) increase in regulating capability should maintain the existing level of regulation performance with the addition of 3,300 MW of wind generation. However, the NYSBPS presently exceeds NERC regulation performance criteria for CPS1 and CPS2. It is possible that the NYSBPS could meet minimum NERC requirements with no increase in regulating capability.

Spinning Reserve: Even with the addition of 3,300 MW of wind generation, no change in the spinning reserve criteria is required. Based on the geographic diversity of the wind across the system, the simultaneous loss of wind throughout the system is not a credible contingency. And while there may be periods of zero wind in the state they are likely to be preceded by periods of very little wind, so that there is no need to change the existing 1,200 MW value as the largest system contingency, as discussed above.

8.5 NYISO Market Design

Current estimates on the day-ahead forecast accuracy for wind are fairly high when viewed across a projected 3,300 MW of wind capacity spread across the state. The accuracy for individual wind farms will not be as high and it may be appropriate for multiple wind farms to merge their forecasts on a zonal or regional basis. The existing day-ahead and hour-ahead energy markets in New York have sufficient flexibility to accommodate wind generation without any significant changes. It may be appropriate for some of the wind generation, for example 75% of the forecast, to bid into the day-ahead market while the balance can be bid into the short-term market. In order to take advantage of the spatial diversity of multiple plants it may also be appropriate to lump the wind generators on a zonal or regional basis rather than treating them as individual plants. It may also be advantageous for the forecasting to be performed from a central location to ensure a consistency of methodologies and so that changing weather patterns can be noted quickly. With these factors in place wind generation can be held accountable to similar standards as conventional generation in terms of meeting their day-ahead forecast.

Care should be taken in the structuring of any financial incentives that may be offered to encourage the development of wind generation. The market for wind generation (including incentives) should be structured to:

- reward the accuracy of wind generation forecasts, and
- encourage wind generators to curtail production during periods of light load and excessive generation.

The second item above is particularly critical to overall system reliability. If excessive wind generation causes the NYISO is forced to shut down critical base-load generators with long shutdown/restart cycle times, the system could be placed in a position of reduced reliability. The market for wind power should be structured so that wind generators have clear financial incentives to reduce output when energy spot prices are low (or negative).

One change that should be incorporated immediately is the accurate recording of forecasts and actual production for all existing and new facilities on at least an hourly and five-minute basis. Shorter time frames, i.e., six seconds, should also be recorded during volatile periods. The existence of this data will greatly facilitate the planning and operations of the system when several thousand megawatts of wind are present.

9 References

[i] Wan, Y.; D. Bucaneg; "Short-Term Fluctuations of Large Wind Power Plants," NREL CP 500-30745, 2002.

[ii] "Overview of Wind Energy Generation Forecasting," AWS TrueWind, report to NYSERDA and NYISO, January 25, 2005

[iii] ibid. pg7-8.

[iv] NYISO manual reference showing timing of day-ahead market

[v] "NYSRC Reliability Rules for Planning and Operating the New York State Power System," New York State Reliability Council, L.L.C., Version 9, January 9, 2004

[vi] "Overview of Wind Energy Generation Forecasting," AWS TrueWind, report to NYSERDA and NYISO, January 25, 2005

[vii] "The Effects of Integrating Wind Power on Transmission Planning, Reliability, and Operations; Report on Phase 1: Preliminary Overall Reliability Assessment." NYSERDA Report, February 2, 2004

[viii] NERC Policy 1, "Generation Control and Performance," (Reference on CPS1 and CPS2)

[ix] "NYCA Variable Regulation Requirements Analysis and Action Plan," NYISO, February 27, 2003

[x] Wan, Y.; D. Bucaneg; "Short-Term Fluctuations of Large Wind Power Plants," NREL CP 500-30745, 2002.

[xi] NREL Data records from an existing wind project in northwestern Iowa

[xii] Zavadil, R.M.; "Wind Generation Technical Characteristics for the NYSERDA Wind Impact Study," January 5, 2004.

[xiii] ibid.

[xiv] FERC NOPR, "Interconnection for Wind Energy and Other Alternative Technologies," Docket No. RM05-4-000, January 24, 2005.